Modelling the Electricity and Natural Gas Sectors for the Future Grid: Developing Co-Optimisation Platforms for Market Redesign

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1 December 2015

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Deliverables 4 and 5:

CSIRO Future Grid Flagship Cluster

Project 3: Economic and investment models for future grids

December 2015

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1 Introduction

This report provides detail on the modelling and scenario frameworks for the economic analysis of the Future Grid. These frameworks and modelling platforms have been constructed to support the Future Grid Cluster in examining policy and market issues which will affect the electricity and natural gas markets in Australia.

Initially we provide an overview of the co-optimisation and expansion of transmission networks and electricity generation for the future grid. In this section we outline not only the key mechanisms and analyses required, but also how we have and will continue to collaborate with the other projects within the Future Grid Cluster.

In section 3 we provide an extensive analysis of the electricity market modelling platform PLEXOS. This section will outline, not only the mechanistic components of modelling electricity markets, but also some of the assumptions which are required to examine issues such as generation investment under uncertainty.

The following section is a discussion of the natural gas modelling platform ATESHGAH. This model has been in construction for several years prior to the commencement of the Future Grid Cluster and represents a significant shift in gas market modelling methodology for Australia, compared to previous approaches. This model is capable of examining multiple issues associated with policy, market, economic, and physical aspects of gas production, transmission, sale and liquefied natural gas (LNG) export simultaneously. We have used this model to examine how Australia's eastern gas market could be affected by the commencement of LNG exports from Curtis Island in 2015/16.

In the remaining section, we present the scenario modelling framework as an overview and present some initial results for Scenario 1: Set and Forget. These results represent the first set of simulations and should thus be viewed as an initial attempt to undertake the large search space that the four scenarios evaluated in the Future Grid Forum encompass.

2 Co-optimisation and Expansion of transmission networks and electricity generation for the Future Grid

The expansion of energy systems and its planning aims to address the problem of expanding and augmenting electricity and natural gas infrastructure, while serving growing demand and fulfilling a variety of technical, economic and policy constraints. Previously, the majority of the energy system had been characterised by vertical integration, which allowed for the optimal least-cost expansion subject to reliability and system constraints.

Since the implementation of market liberalisation [1-3], and the deregulation of the previous vertically integrated supply chain into a number of horizontal components [4], there have been a number of conflicting planning objectives which include:

1. The promotion of competition amongst electricity market participants by the implementation of an aggregated spot market pool [5, 6]:
    - The maximization of social welfare now occurs in a market based environment (i.e. the pool based market mechanisms [7, 8] and bilateral contracts)
    - Market participants can hedge risk via forward contract markets (contracts for difference) which lower the probability of wholesale energy price spikes affecting consumers [9]
    - These market features provide non-discriminatory access to the lowest cost generation sources for all consumers connected to the main grid [10].

2. Facilitation of the early adoption of more efficient and lower cost generation technology types [11]:
    - Enhances the proliferation of generation assets which have a higher level of operational flexibility [12]
    - The development of advanced technology such as Ultra-Super Critical Coal fired power stations [13].

3. Promoting the deployment and integration of renewable energy sources such as wind and solar [14], which will lead to:
    - Mitigation of carbon emissions from the stationary energy sector [15]

- Diversification of fuel sources [16, 17].

4. Encouraging demand side participation via:
    - Demand side management (DSM) [18, 19]
    - Distributed Generation (DG) [20]
    - Localisation of Storage [21, 22].

5. Constructing a robust and resilient physical electricity network which can adapt to and enable processes which will:
    - Ensure that the occurrence of network congestion remains low [23, 24]
    - Reduce transmission losses
    - Provide fair and adequate supply-side and demand-side reserves for all economic agents in the system (for supply-side agents [25, 26] and demand-side agents [27, 28])
    - Promote resilience to uncertainties such as weather-related extreme events [29]
    - Fairly price consumer security of supply requirements based on actual risks [30], rather than via fault-tolerant risk criterion values [31].

The deregulation and vertical restructuring of the power sector may lead to a significant increase in the uncertainties and risk that central planner's face when trying to maintain adequacy of the energy system. Furthermore, this increase in risk and uncertainty may decrease the potential options available to policy makers [32]. We now briefly outline the uncertainties for power system planning in the future grid, which can be categorised into two main elements:

1. Random uncertainties [33]
    - Demand (load)
    - Generation costs
    - Bidding behaviour of generating units
    - Availability of transmission capacity
    - Generation asset availability
    - Production from renewable energy sources.
2. Non-random uncertainties [34-36]
    - Generation investment and retirement

- Load expansion and removal
- Transmission network augmentation
- Market rules and regulatory processes
- Fuel costs and availability
- Inflation or interest rates
- Environmental regulation
- Public Perception
- The dynamics of other energy and financial markets.

This project utilizing its gas and electricity market modelling platforms (outlined in Sections 3 and 4) has the capability to examine gas scheduling and its influence on outputs of both the gas and power sectors. Furthermore, this combined modelling approach has the potential to integrate gas market operations into system adequacy questions which relate to power system reliability.

This project however, will not examine the effects of contracts, be they short- or long-term on the natural gas market. It is likely that long-term contracts will be priced at the expected value of long-term production costs with an added risk premium. However, we briefly mention how our analysis could take into account gas market contracts and operations. Medium- to long-term gas market scheduling is executed somewhat in accordance with gas supply contracts.

In general terms, there are usually four types of gas supply contracts which warrant discussion: long-term contracts; fixed delivery of volume and timing; flexible delivery of volume and timing, and; the Take-or-Pay (ToP) contract arrangement. While supplementary to bilateral over-the-counter arrangements, transactions on the gas spot market are mainly to offset quantity deviations [37] and provide market liquidity and an indexed price for long-term contracts.

To remain competitive, the majority of Open Cycle Gas Turbines (OCGT) require the use of the more flexible and ToP type gas contracts. This reflects the price of these contract types are typically below the other contract types previously mentioned. Thus, a consequence of these types of contracting is that during periods of gas market infrastructure and supply disruptions, gas-fired powered generation (GPG) of all types are likely to be curtailed first.

Furthermore, from a market operations perspective, non-electricity/LNG based consumers (such as residential customers) should have a higher positioning on the schedule for dispatch. This project has the capability to examine the prospect of insufficient gas supplies and how this may compromise the power outputs of GPG units which may jeopardize the reliability of the power system. Thus, gas transmission limits should also be taken into account when examining the electricity generation capacity of GPG units as well as the possible shifts in gas supply due to system curtailment and gas system operations.

In collaboration with the Universities of Newcastle and Sydney, our co-planning objective is to maximize the overall social welfare function of consumers and to minimize total network expansion and generation capacity costs.

In collaboration with Projects 1 and 2, our goal is to establish an integrated natural gas and electricity market suite of constraints to understand system operational limits. The fundamental constraints are transmission and supply constraints that involve the combinations of generation/production, demand and line/pipeline flow. The transmission constraints refer to technical limits for both gas pipelines and power lines. The supply constraints refer to both gas production fields and power generators.

2.1 Collaboration with Projects 1 and 2

There are two ways in which Project 3's database can be used: 1) some scenarios proposed by P3 will be incorporated into P1 and P2 models, such as carbon prices, renewable energy certificate prices forecast, fuel prices, etc. ;2) the gas price forecast, which can be considered as gas production costs by basin/node. Next, a central gas dispatch scheme is performed based on those costs of gas providers. Then we simulate gas prices in spot markets (bidding to provide gas) to better inform the cluster of prevailing fuel price conditions. More specifically, gas prices in Project 3's models will be gas production costs in models of P2. This is due to the modelling platforms design purpose which is to provide gas prices from P2 models which are simulation results/outputs, reflecting gas demands as well as the market interactions between gas and power markets.

3 Electricity Market Simulation Platform.

Modelling the National Electricity Market (NEM) has been conducted using a commercially available electricity market simulation platform known as PLEXOS [38] provided by Energy Exemplar. The core implementation of optimisation algorithms which drive this software platform are primarily Linear Programming (LP), Non-Linear Programming (NLP), Mixed Integer Programming (MIP), Quadratic Programming (QP), and Quadratic Constraint Programming (QCP). Furthermore, the platform requires a number of third party industrial solvers such as Gurobi, CPLEX and MOSEK to perform the transmission and generation expansion planning.

PLEXOS utilizes these solvers in combination with an extensive input database of regional demand forecasts, transmission thermal line limits and generation plant specifications to produce price, generator behavioural characteristics (bidding behaviour) and demand forecasts to replicate the NEM dispatch engine (NEMDE, formerly SPD (scheduling, pricing and dispatch)) which is used by the Australian Energy Market Operator (AEMO) to operate the market.

PLEXOS is a mature, and well respected modelling package and which is currently in use in similar modelling-related research, including modelling the impact of electric vehicles on Ireland's electricity market [39, 40]. Furthermore, PLEXOS can provide a highly accurate prediction of prices and has been used to model market behaviour following the introduction of carbon prices [41].

PLEXOS' least cost expansion algorithm and planning tools, as used in this study and by AEMO [42], provides the optimal generation capacity mix given the current and forecasted policy constraints [12, 43, 44].

Project 3 has specifically chosen PLEXOS as the key modelling platform for the Future Grid Cluster given our previous research in modelling the future electricity grid and the competitiveness of Australia's electricity sector [45-47], and the platform is populated with Australia's NEM data [42, 48, 49] to enable robust modelling of the NEM.

In this project report, we now provide a short overview of the methodologies that PLEXOS uses to simulate the electricity market and to evaluate its optimal expansion. The reader should note however, the full description of the algorithmic development and methods that PLEXOS employs are subject to commercial-in-confidence agreements.

PLEXOS breaks down the simulation of the NEM into a number of phases which range in scope and scale. These time-scales range from: year-long generation expansion planning and constraint evaluation; security and systematic supply requirements; network expansion down to hourly dispatch and market clearing. Although PLEXOS has the capability to perform five-minute dispatch we will follow the method used by the Future Grid Forum [50] and AEMO's National Transmission and Network Development Plan [42], which both use hourly dispatch periods. This particular time scale is most useful in simulating long-term electricity market structural behaviour patterns and in an effort to reduce the computational requirements of this study. The operation and the interaction between these modelling phases is shown in **Figure 1**. We shall now explore briefly the operational aspects of PLEXOS and the methodologies it employs to simulate the electricity market.

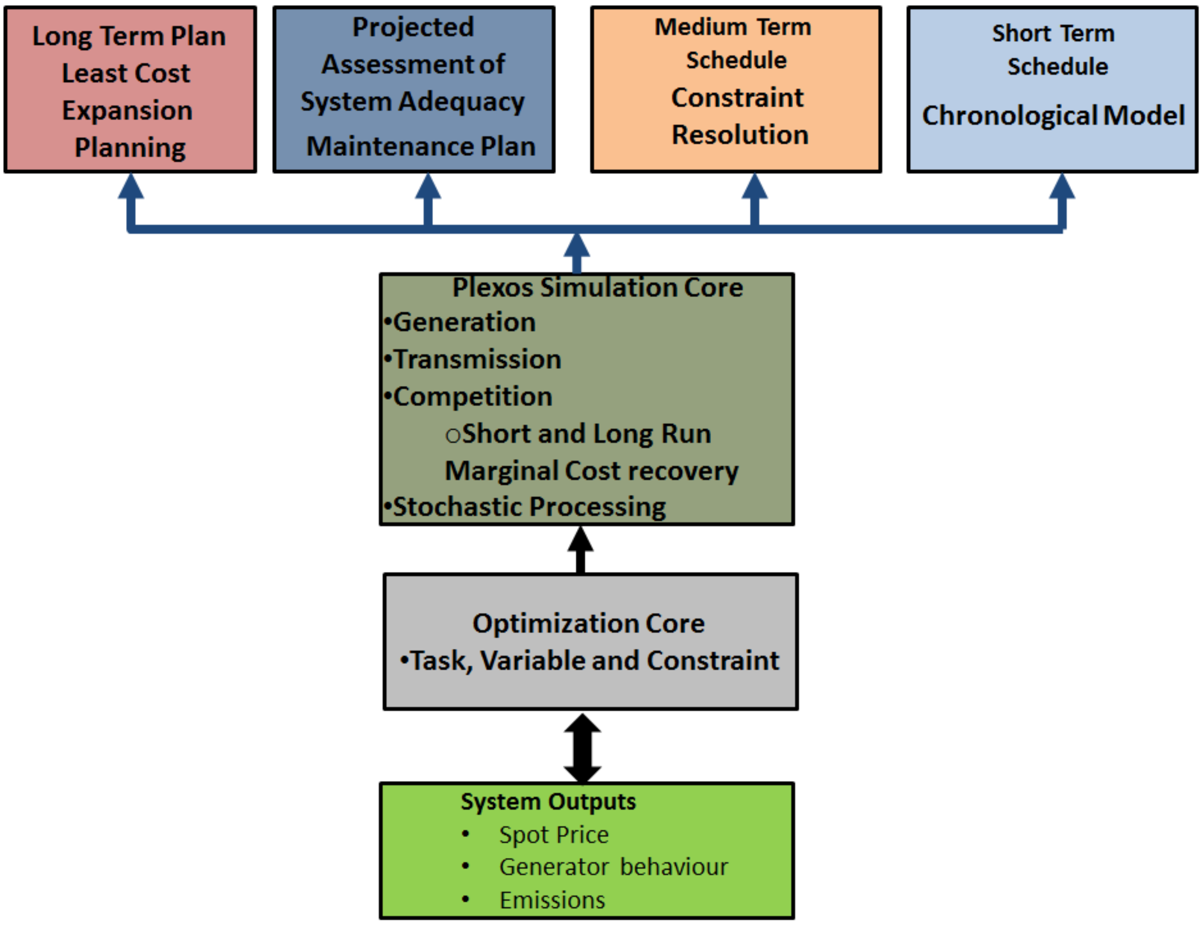

Figure 1: PLEXOS Simulation Core

3.1 Optimal Power Flow Solution

The solution to the optimal power flow (OPF), is one of the core functions of the PLEXOS simulation engine which utilizes a linearized version of the direct current (DC) approximation for the optimal power flow problem to model transmission congestion and marginal thermal losses. In PLEXOS the locational marginal prices (LMP) are reflective of transmission marginal loss factors as well as congestion throughout the system. Further, the congestion modelling results are also an indicator of long-term constrains within sub-branch loops (such as the Tarong loop in Queensland), which may require capacity upgrades in the future.

However, PLEXOS does not perform any pre-computation or impose any restrictions on how dynamic the network data may be, thus it can model transmission augmentations and transmission outages dynamically. PLEXOS thus optimizes the power flows using a linearized DC approximation to the AC power flow equations. This model is completely integrated into the mathematical programming framework that results in the realistic simulation of generator dispatch, transmission power flows and regional reference pricing which are jointly optimized with the power flow solution.

3.2 LT Plan

The long-term (LT) planning phase of the PLEXOS model establishes the optimal combination of new entrant generation plant, economic retirements, and transmission upgrades which will minimize the net present value (NPV) of the total costs of the system over the planning horizon (as detailed in Figure 2). The following types of expansions/retirements and other planning features are supported within the LT Plan:

- Building new generation assets (including multi-stage projects)
- Retiring existing generation plant
- Upgrading the capacity of existing transmission lines
- New build transmission line infrastructure (including multi-stage projects).

Furthermore, the PLEXOS least cost expansion planning phase also allows the tactful inclusion of global and domestic policy drivers into its input data set. While the scenario development capability of PLEXOS is an important issue into its operation, the parametrization and input is user-defined and labour intensive.

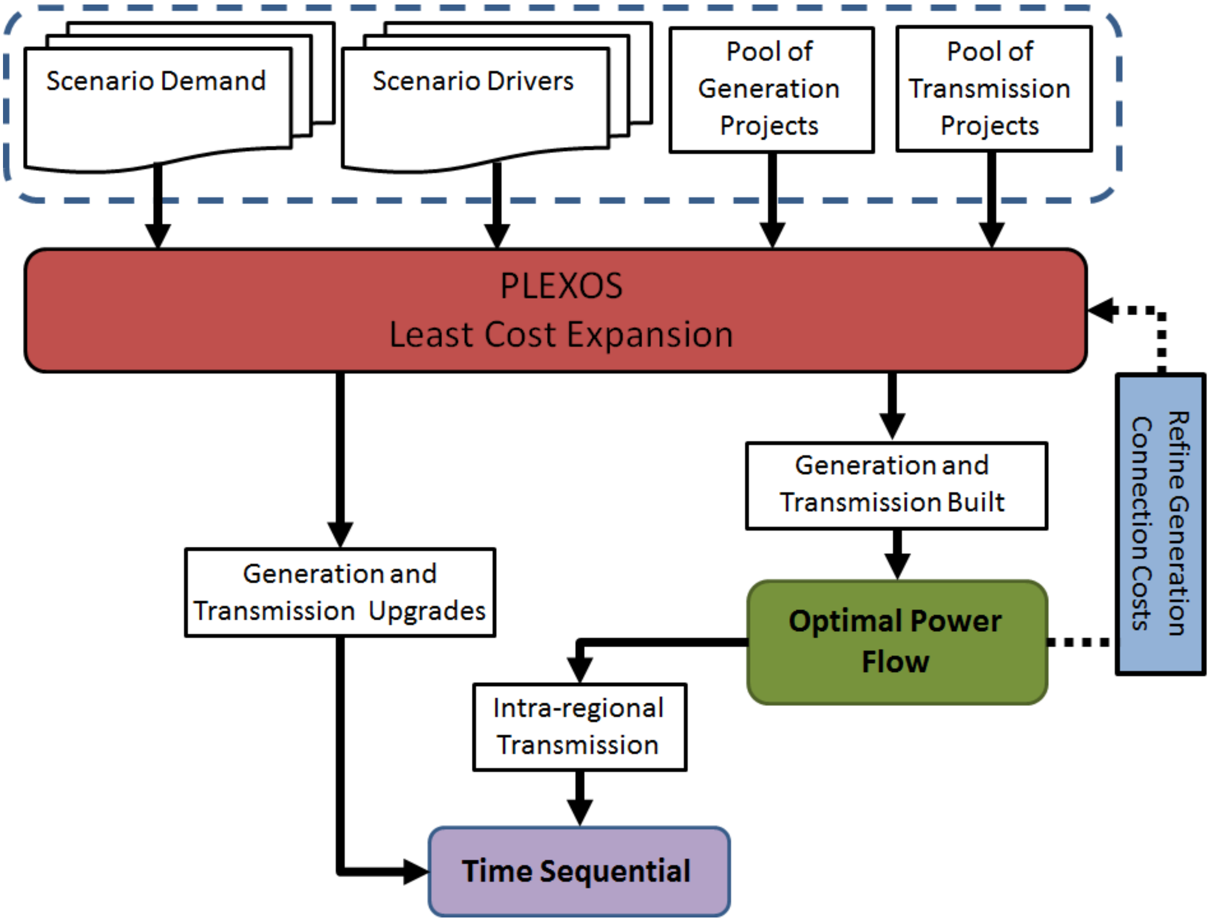

Figure 2: PLEXOS Least Cost Expansion Modelling Framework

3.3 PASA

The Projected Assessment of System Adequacy (PASA) schedules maintenance events such that the optimal generation capacity is available and distributed suitably across interconnected regions. The PASA phase of the model allocates/samples discrete and distributed maintenance timings and random forced outage patterns for generators and transmission lines. This ability to sample forced and planned outage patterns allows for uncertainty in generation plant availability and informs the LT Plan expansion phase of the model of further capacity requirements.

3.4 MT Schedule

The Medium Term (MT) Schedule is a model based on Load Duration Curves (LDC) (also known as load blocks), that can run on daily, weekly or monthly resolutions which includes a full representation of the power system and major constraint equations, but without the complexity of individual unit commitment. The MT Schedule models constraint equations including those that span several weeks, or months of a year. These constraints may include:

- Fuel off-take commitments (i.e. gas take-or-pay contracts)
- Energy limits
- Long term storage management taking into account inflow uncertainty
- Emissions abatement pathways.

Each constraint is optimized over its original timeframe and the MT to ST Schedule's bridge algorithm converts the solution obtained (e.g. a storage trajectory) to targets or allocations for use in the shorter step of the ST Schedule. The LDC blocks are designed with more detailed information concerning peak and off-peak load times and less on average load conditions, thus preserving some of the original volatility.

The solver/s used by PLEXOS will then schedule generation to meet the load and clear offers and bids inside these discrete blocks. System constraints are then applied, except those that define unit commitment and other inter-temporal constraints that imply a chronological relationship between LDC block intervals. The LDC component of the MT Schedule maintains consistency of inter-regional load profiles which ensures the coincident peaks within the simulation timeframe are captured. This method is able to simulate over long time horizons and large systems in a very short time frame. Its forecast can be used as a stand-alone result or as the input to the full chronological simulation ST Schedule.

3.5 ST Schedule and Spot Market Dispatch

The Short Term (ST) Schedule is a fully featured, chronological unit commitment model, which solves the actual market interval time steps and is based on mixed inter programming. The ST Schedule generally executes in daily steps and receives information from the MT Schedule which allows PLEXOS to correctly handle long run constraints over this shorter time frame.

PLEXOS models the electricity market central dispatch and pricing for each state on the NEM via Regional Reference Nodes (RRN). This is achieved by determining which power stations are to be included for each dispatch interval in order to satisfy forecasted demand.

To adequately supply consumer demand, PLEXOS examines which generators are currently bid into the market as being available to generate for the market at that interval. This centralised dispatch algorithm uses the LP dispatch algorithm SPD to determine which generators in the dispatch set in the given trading interval, taking into account the physical transmission network losses and constraints can serve load.

Each day consists of 24 hour trading periods, and market scheduled generation assets have the option to make a supply offer for a given volume (MW) of electricity at a specified price ($/MWh) across 10 bid bands. Each band, consists of bid price/quantity pairs which are then included into the nodal bid stack.

Following the assembly of the generator bid pairs for each bid band, the LP algorithm begins with the least cost generator and stacks the generators in increasing order of their offer pairs at the node, while taking into account the transmission losses. The LP algorithm then dispatches generators/power stations in merit order, from the least cost to the highest cost until it dispatches sufficient generation to supply the forecasted demand with respect to the inter-regional losses. This methodology replicates not only the NEM dispatch process but is similar in construction to the least cost "Dutch Auction" [51, 52].

The price of the marginal generating unit at each time interval determines the marginal price of electricity at the RRN for that given trading period. It should also be noted that this dispatch process and the ST Schedule have the following properties:

- The dispatch algorithm calculates separate dispatch and markets prices for each node and then for the Regional Reference Price for each state of the NEM
- Generator offer pairs determine the merit order for dispatch which and are adjusted with respect to relevant marginal loss factors
- The market clearing price is the marginal price, not the average price of all dispatched generation (as per the "Dutch Auction" market design [53, 54]).
- Price differences across regions are calculated using inter-regional loss factor equations as outlined by AEMO [42, 49].

PLEXOS can produce market forecasts, by taking advantage of one of the following three generator bidding behavioural models for cost recovery and market behaviour methodologies:

- Short Run Marginal Cost Recovery (SRMC, also known as economic dispatch)
- User defined market bids for every plant in the system
- Long Run Marginal Cost Recovery (LRMC).

3.6 Short Run Marginal Cost Recovery Algorithm

The core capability of any electricity market model is to perform the economic dispatch or Short Run Marginal Cost (SRMC) recovery based simulations of generating units across a network to meet demand at least cost. PLEXOS' platform performs economic dispatch under perfect competition where generators are assumed to bid faithfully their SRMC into the market. While simulations such as these will never result in a price trace which would match historical market data from an observed competitive market, they provide a lower bound representative of a pure competitive market.

3.7 Long Run Marginal Cost Recovery

PLEXOS has implemented a heuristic Long Run Marginal Cost (LRMC) recovery algorithm that develops a bidding strategy for each generating portfolio such that it can recover the LRMC for all its power stations. This price modification is dynamic and designed to be consistent with the goal of recovering fixed costs across an annual time period. The cost recovery algorithm runs across each MT Scheduled time step. The key steps of this algorithm are as follows:

1. The MT Schedule is run with 'default' pricing (i.e. SRMC offers for each generating units)
2. For each firm (company), calculate total annual net profit and record the pool revenue in each simulation block of the LDC
3. Notionally allocate any net loss to simulation periods using the profile of pool revenue (i.e. periods with highest pool revenue are notionally allocated a higher share of the annual company net loss)
4. Within each simulation block, calculate the premium that each generator inside each firm should charge to recover the amount of loss allocated to that period and that firm equal to the net loss allocation divided by the total generation in that period – which is referred to as the 'base premium'
5. Calculate the final premium charged by each generator in each firm as a function of the base premium and a measure how close the generator is to the margin for pricing (i.e. marginal or extra marginal generators charge the full premium, while infra-marginal generators charge a reduced premium)
6. Re-run the MT Schedule dispatch and pricing with these new premium values
7. If the ST Schedule is also run, then the MT Schedule solution is used to apply short-term revenue requirements for each step of the ST Schedule and the same recovery

method is run at each step. Thus, the ST Schedule accounts for medium-term profitability objectives while solving in short steps.

In using PLEXOS, this project has set the LRMC recovery algorithm to run three times for each time step to produce price trace forecasts with sufficient volatility and shape as recommended by the software's vendor, Energy Exemplar. This will ensure that under normal demand conditions, generating units will bid effectively to replicate market conditions as seen in the NEM. It should be noted that the actual dispatch algorithm in this process is still an LP based protocol which is in contrast to other commercial tools that use much slower heuristic rule based algorithms to solve for LRMC recovery.

3.8 Data and assumptions

At the time of initiating this modelling the only publicly available PLEXOS data set that is available is AEMO's NTNDP 2014 [42]. However, this database requires significant upgrading/repurposing so the database developed for this project was developed using the NTNDP dataset and other publicly available data. Prior to this project a former database to the NTNDP was used to model wholesale market behaviour in other related research such as: the deployment of plug-in hybrid electric vehicles [55], distributed generation [20] and the competitiveness of renewables [46]. The data and assumptions used to populate the database have been developed such that the completed database includes the following details:

- Capacity factors (%)
- Ramp rates (MW/min)
- Emissions intensity factors (kg-CO_2/MWh)
- Fuel costs ($/GJ) for coal, oil, distillate and natural gas
- Gas transport costs ($/GJ), where Moomba used as the NEM reference price
- Variable and fixed operating and maintenance costs ($/MWh and $/MW/year respectively)
- Scheduled outage rates and probability of forced outage rates (% hours/year).

3.8.1 Generation capacity and investment

Historical generation plant behaviour was sourced from AEMO's data server [56], with technical specifications for all current generation assets sourced from AEMO, ACIL, Worley Parsons and BREE ([42, 48, 49, 56-60]). Particular attention was given to generation plant with long-term supply contracts which were likely to be in place from 2030 onwards. Inclusion of the above data provided an accurate predictor of generation plant likely to be economically and technically feasible [42, 48, 49, 56, 61-65] for operation in 2035.

3.8.2 Fuel Prices

The cost projections for coal for use in QLD, NSW and VIC power generation were sourced from recent assessments on fuel prices by AEMO and others [42, 48, 49, 56-60, 63, 66, 67]. Furthermore, due to the lack of infrastructure to support international trade, coal prices for power generation are projected to remain subdued and stable until 2050. Natural gas costs and market conditions are the subject of another model which will be discussed in Section 4.

3.8.3 Network

The network topology used within the modelling framework was initially sourced from AEMO's NTNDP [42], with its corresponding constraints on inter-region transmission flow. Upgrades to the network for this paper were only assumed if they had been previously announced or currently under consideration by the market operator AEMO or the Australian Energy Regulator (AER). Furthermore, the optimal expansion of the transmission network will be discussed further in this report in collaboration with Projects 1, 2 and 4.

4 Natural Gas Market Modelling

Australia is in a key geographic and strategic position to supply a sizable proportion of the Asia Pacific regions' LNG demand, and potentially be one of the world's largest suppliers (see [68]). Current trends in the development of the natural gas industry, particularly in Western Australia, have shown that the internationalization of prices can have a significant impact on electricity prices [69], carbon emissions [45, 47, 70], and the availability of gas for industrial users [71]. The effects of the expected uplift in prices with trade between two markets, price in each adjusts depending on the elasticities of supply and demand (see Figure 4).

Further, the arbitrage opportunities which are presented to US produces to the detriment of Australia's interests are also of concern, such that the prevailing spot price in Japan has historically been much higher than the comparative European ports [72]. The newly improved transport cost conditions (due to the upgrade of the Panama Canal) make East Asian markets a very attractive prospect for US shale gas producers [73, 74].

While the demand for natural gas in Australia pales in comparison to its export potential [71], there are numerous concerns surrounding the potential effects that exports may have on industrial users and electricity generators. These competing interests are also apparent, particularly between state governments, who are likely to receive a significant boost in resource rents and somewhat higher availability of cheap supply for domestic consumption.

Aside from the significant coal reserves in Queensland, one of the key drivers for coal seam gas exploration was the implementation of the Gas Electricity Scheme in 1994 [75, 76]. Accredited electricity generators could create tradable certificates which represented one MWh of eligible generation. The schemes initial intention was to diversify the generation mix, encouraging gas exploration and to offset the then high costs of using natural gas. This inherent interest in using gas from electricity in Queensland was complemented by the growing concern for reducing greenhouse gas emissions.

Similarly the New South Wales (NSW) government in 2003 implemented the NSW Greenhouse Gas Abatement Scheme (NGGAS), which mandated a reduction in CO_2 emissions per capita by 2007. The development of new gas powered generation assets which could supply electricity to NSW (natively or by transmission interconnection) were thus capable of contributing to this abatement target. These two schemes were closed in 2013 and 2012 respectively due to the significant discovery of natural gas resources in QLD and the introduction of national emissions reduction legislation [77].

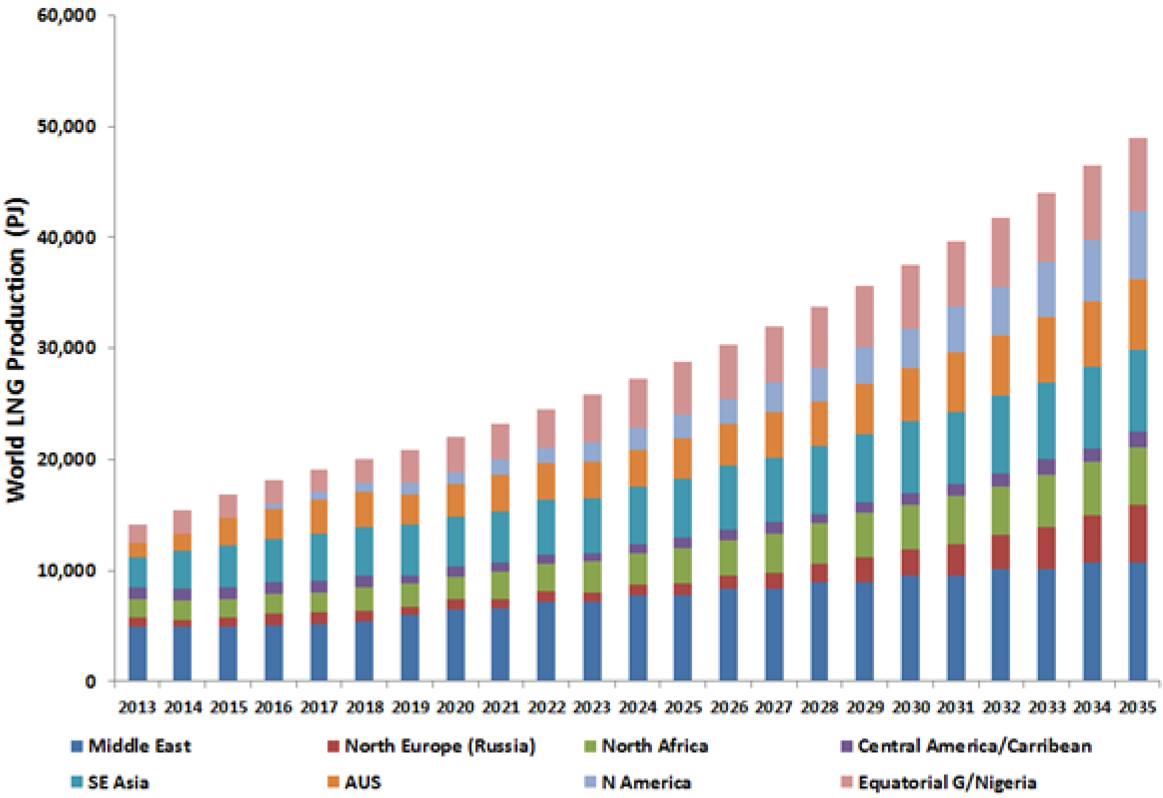

Figure 3: World Gas Production Optimistic Case

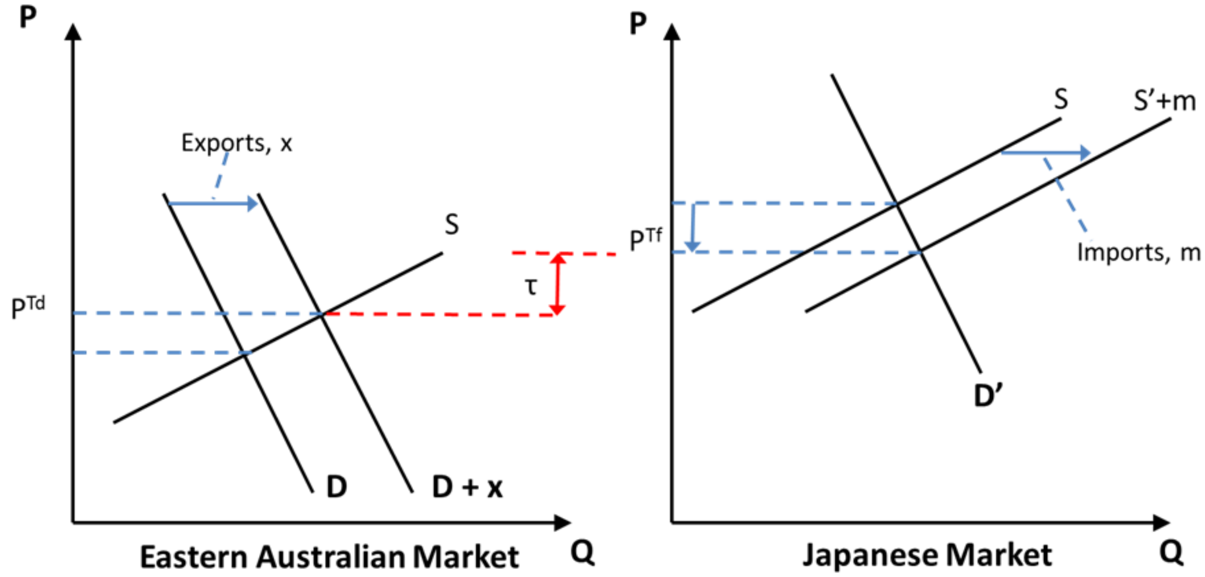

Figure 4: The effects of international market linkage

The modelling framework ATESHGAH [78, 79], is well placed within the international energy literature which has an extensive history of implementing Complementarity models for examining oil and natural gas markets [80-82]. Many of these models that were developed, address fundamental policy issues affecting natural gas markets. For example: the disruption of Russian gas supplies via the Ukraine [83]; intra-European trade and capacity bottlenecks [84, 85]; the potential cartelization of global gas markets [86]; the influence of Eurasian gas supplies, and; the strategic implications of the South Stream pipeline [77]. The use of Complementarity methods has also been used in a variety of studies which examine the market liberalization process in a number of international contexts [87].

This report summarizes the inputs and overarching assumptions for the Non-Linear Program (NLP) which in turn applies the Mixed Complementarity Problem (MCP) based framework, to examine multi-producer oligopolistic agent behaviour via Nash-Cournot equilibrium in the Eastern Australia natural gas market (EGM). This modelling platform has been developed in GAMS to take advantage of its ability to model both economic problems, but also its implementation of the MCP solver known as PATH [88-90]. More specifically, this deterministic and myopic model examines the production trends, system adequacy and capacity, and nodal spot prices, over a multi-period time scale (2015-2030).

The model developed by Wagner [78], is focused on analyzing the international linkages that the EGM will have with its main export partners in Asia and the likely effects on production and wholesale gas costs. The economic behaviour of agents in this newly minted internationalized market is modelled via an optimization problem and market clearing conditions. The principle agents which we have considered here are producers, traders/marketers, and consumers in three crucial sectors (GPG, MMLI and LNG). The roles of end-users and marketers have been simplified so that a producer who would normally face several intermediaries before delivering to the final consumer, faces an aggregated demand curve for each node in the network. In contrast to other models whose implementation of multiple staged games [86] link several demand curves and a border price which would overly complicate this model. We have assumed that producers act as semi-vertically integrated agents whose roles fit more in context with the EGM [71, 78].

The primary objective for creating this model was to examine the strategic interactions between the producer agents and LNG exporters. We have implicitly assumed that there is no material benefit for disaggregating traders/marketers from the supply side. As noted above, the aggregation of these roles is a reasonable and necessary assumption given that producers such as Arrow and Origin not only sell at the bulk supply level, they consume natural gas as a production input into markets such as GPG and LNG. Furthermore, as we only consider yearly time intervals for demand we are able to avoid any issues with long-term contracts for supply and spot market behavioural issues which is in keeping with the international experience with modelling these types of markets [91-93] and more specifically their linkage/interconnection [94].

4.1 Data

The purpose of this model is to provide a comprehensive representation of all producers in the EGM. The data set includes all producing fields (by owner/operator), pipelines (transmission and major laterals) and demand by the three main gas consuming sectors within the interconnected eastern market.

We assume that there is an integrated producer/trader/marketer agent whose objective is to maximize profits when faced with nodal inverse demand curves. The lack of data availability on nodal Mass Market (MM) and Light Industrial (LI) demand (excluding utility gas powered generation), is one of the limitations of this model. Aggregate historical and forecasts of demand for the combined sector MM/LI is used to maintain the appropriate level of scope for this analysis. Similar agent aggregations have also been seen in the international literature, and the experience with modelling the European [83, 91, 93] and US markets [92], further justifies our methodology.

Initially the base year 2013, is used to parametrize the model for simulation, which allows us to establish the yearly and long-term structural consequences of international market linkage for the EGM with its key Asian trading partners. The literature which examines similar markets/regional trade blocks, has deemed it sufficient to evaluate these situations via yearly time steps [86, 92, 95]. The omission of daily or seasonal effects associated with demand may lead to different results, especially in the presence of binding transport constraints and high levels of capacity utilization. However, the use of storage and inter-period arbitrage by producers/processors can overcome some of these difficulties [92, 95].

The data and analysis presented in this report are represented in SI units. Therefore, reserves are expressed in petajoules (PJ); production, transport capacity and demand in PJ/year, which allows for us to neglect differential qualities and facilitate constraint qualifications to be uniformly applied. We shall now explore the construction of the base case data set and detail the possible scenarios and their implementation.

The availability of resources in the EGM has been sourced from the technical literature [83, 86], state and federal regulators [71, 96, 97], the market operator [98-100], industry analysts [66, 101-103] and corporate reporting [104, 105] (also see Figure 5). The discovery, firming up and transformation of reserve tranches are all sourced and calculated exogenously to this modelling framework [97, 102, 103]. The 13 basins' reserve and resource base case data is shown below in Table 1 and Table 2 (by basin and by resource type). It should be noted that each basin is associated with a single resource type. For example, the resources associated with Surat/Bowen are considered conventional natural gas, whereas the Bowen and Surat Basins rows describe the distribution of coal seam gas.

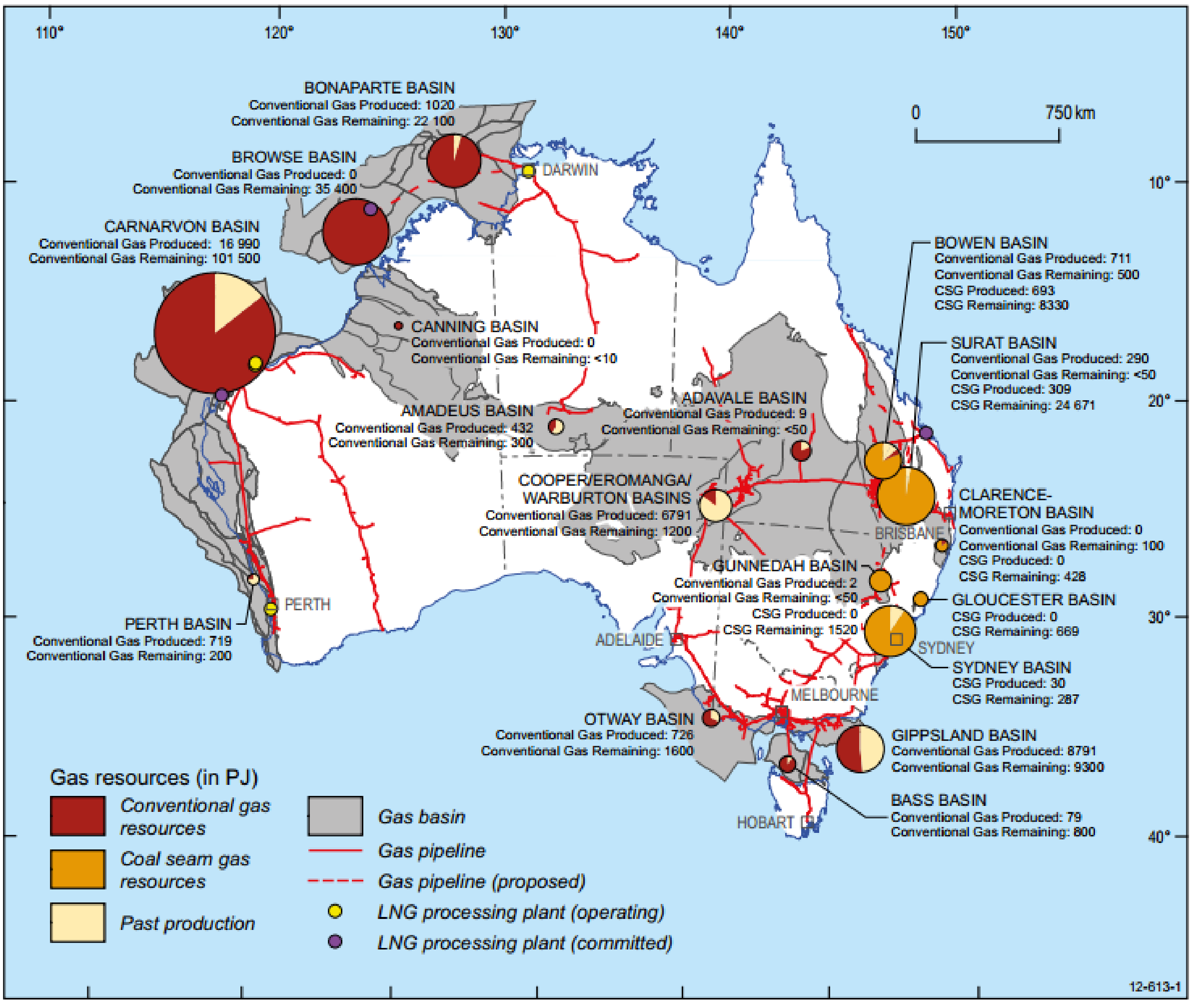

Figure 5: Australia's natural gas basins. Source: Geoscience Australia

Production costs have been sourced from a range of commercial services, industry reports and government reports [71, 100]. Each field is composed of tenures and grouped by geological formation and owner/developer (as in [106, 107]). Each field (producing area) has detailed estimates of reserves and resources with a range of costs associated with extraction (cf. [99]). The costs associated with each tranche of possible production is then used to calibrate the supply cost curve (via the Golombek supply cost function [108]).

Table 3 shows example fields with corresponding reserves and costs. We also provide the cumulative cost curve for natural gas by production tranche within each basin (see Figure 6). It shows that 50% of all available reserves have an expected production cost of \$5.16/GJ, which far exceeds the expected average cost of US shale gas production at \$2-3/GJ? [92, 109].

Table 1: Natural Gas Reserves within the Eastern States

Basin	Resource Type	2P (PJ)	3P (PJ)	2C (PJ)	3C (PJ)	URR (PJ)
Bass	Conventional	338	250	360	268	726
Bowen	CSG	8,535	25,130	4,345	2,834	31,488
Clarence/Moreton	CSG	445	2,922	2,511	629	6,062
Cooper/Eromanga	Mixed	2,198	1,901	6,416	244	8,488
Galilee	CSG	-	-	259	1,634	1,634
Gippsland	Conventional	3,890	3,859	1,094	10,000	14,192
Gloucester	CSG	669	832	-	-	832
Gunnedah	CSG	1,426	1,426	3,460	-	4,886
Maryborough	Shale	-	3,000	-	-	3,000
Otway	Conventional	604	-	274	-	878
Surat	CSG	28,835	38,831	11,979	-	50,810
Surat-Bowen	Conventional	76	106	2,000	-	2,106
Sydney	CSG	424	728	-	-	728
Totals		47,440	78,985	32,698	15,609	125,830

Table 2: Natural gas reserves by resource type

Resource Type	2P (PJ)	3P (PJ)	2C (PJ)	3C (PJ)	URR (PJ)
Conventional	1,790	2,007	4,176	244	6,349
CSG	40,334	69,868	22,554	5,097	96,440
Offshore	4,832	4,109	1,728	10,268	15,796
Shale	-	3,000	-	-	3,000
Unconventional	5	-	4,240	-	4,245
Totals	47,440	78,985	32,698	15,609	125,830

Table 3: Field reserve and production cost data example

Node	Roma	Spring Gully	Kogan
Field	Roma OA	ATP 592	Kogan East
State	QLD	QLD	QLD
Producer	Santos	Origin	Arrow
Basin	Surat	Bowen	Surat
Region	Walloons (West)	Fairview	Walloons (East)
Resource Type	CSM	CSM	CSM
	Reserves and Resources (PJ)		
2P	1824	232	60
3P	2416	682	79
2C	758	96	25
URR	3174	779	105
	Production Costs ($/GJ)		
Low	3.13	1.93	1.40
Mid	5.04	3.17	3.80
High	6.06	3.81	4.24

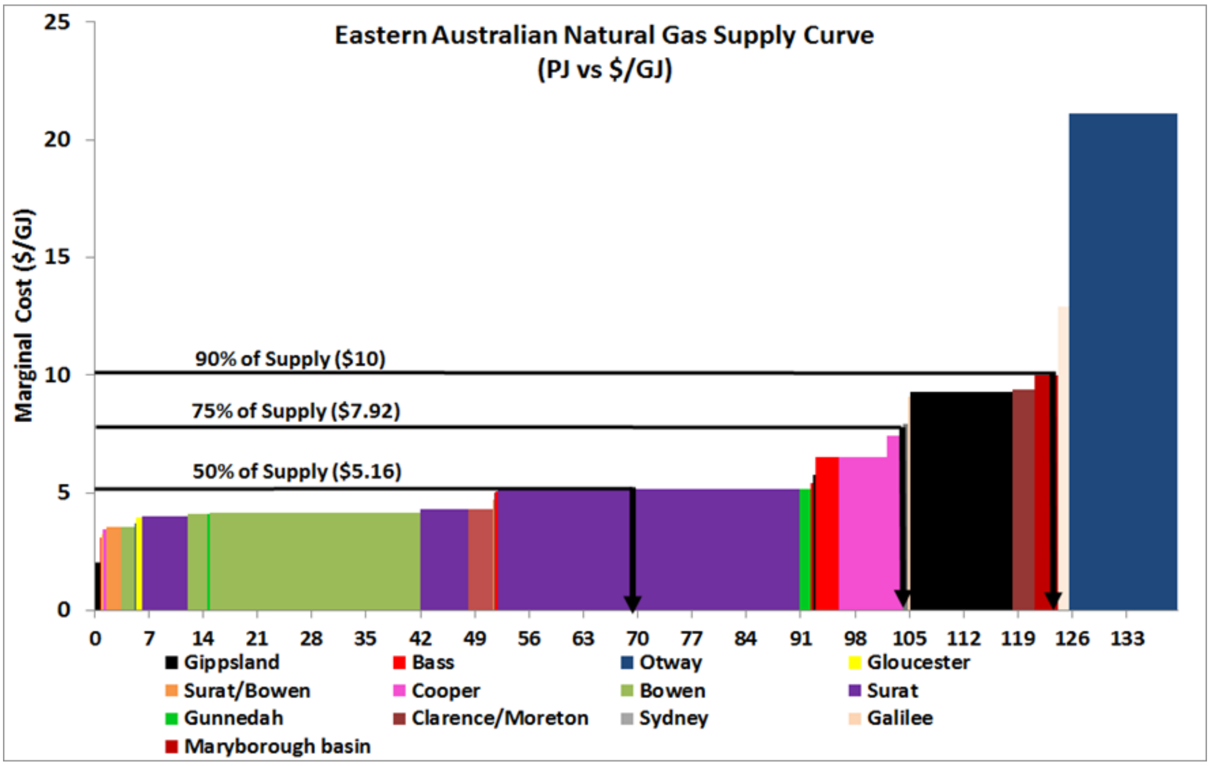

Figure 6: Marginal Cost Curve for the Eastern Australian Gas Market

The functional form of the Golombek primary cost function

$$C_i(v_i) = \alpha * v_i + \frac{1}{2}\beta * v_i^2 - \gamma * (V_i - v_i) * \ln\left(1 - \frac{v_i}{V_i}\right) - \gamma * v_i, \qquad (1)$$

The marginal cost function is as follows:

$$MC_i(v_i) = \alpha + \beta * v_i - \gamma * \ln\left(1 - \frac{v_i}{V_i}\right), \qquad (2)$$

where vi, is the volume of production in time t, α is the minimum cost of production, β and γ are parameters fitted to the change in production costs associated with accessing increasingly deeper and more difficult to extract gas and Vi is the remaining reserves. The sensitivity of each of the aforementioned coefficient is presented in **Figure 7**. We present three key supply fields with their associated Golombek coefficients in **Table 4** and an example of the marginal cost curve for the unconventional Cooper/Eromanga fields in **Figure 7**.

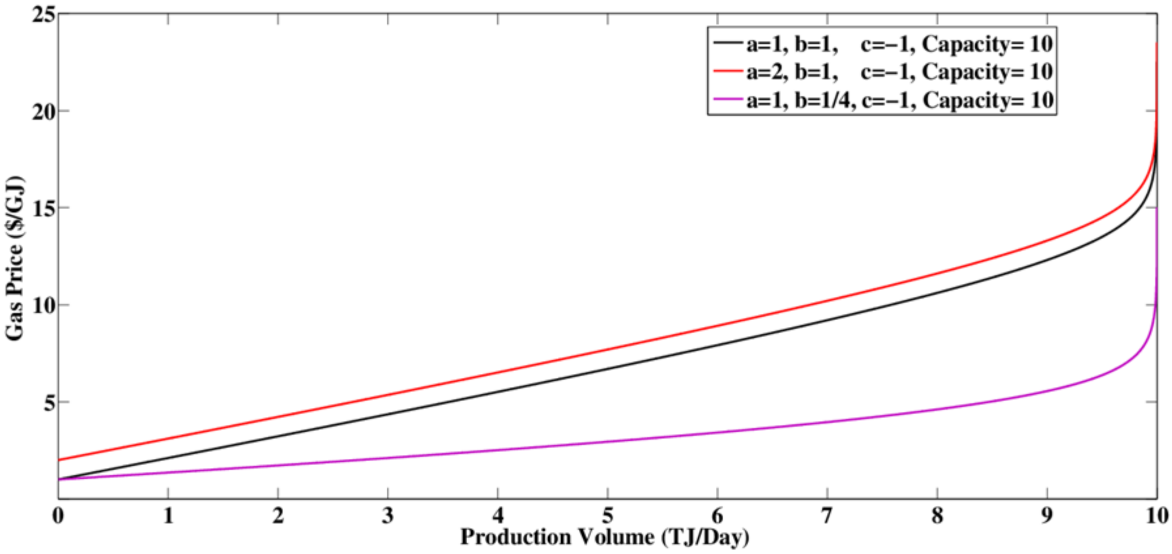

Figure 7: Sensitivity of the Golombek marginal cost of supply curve

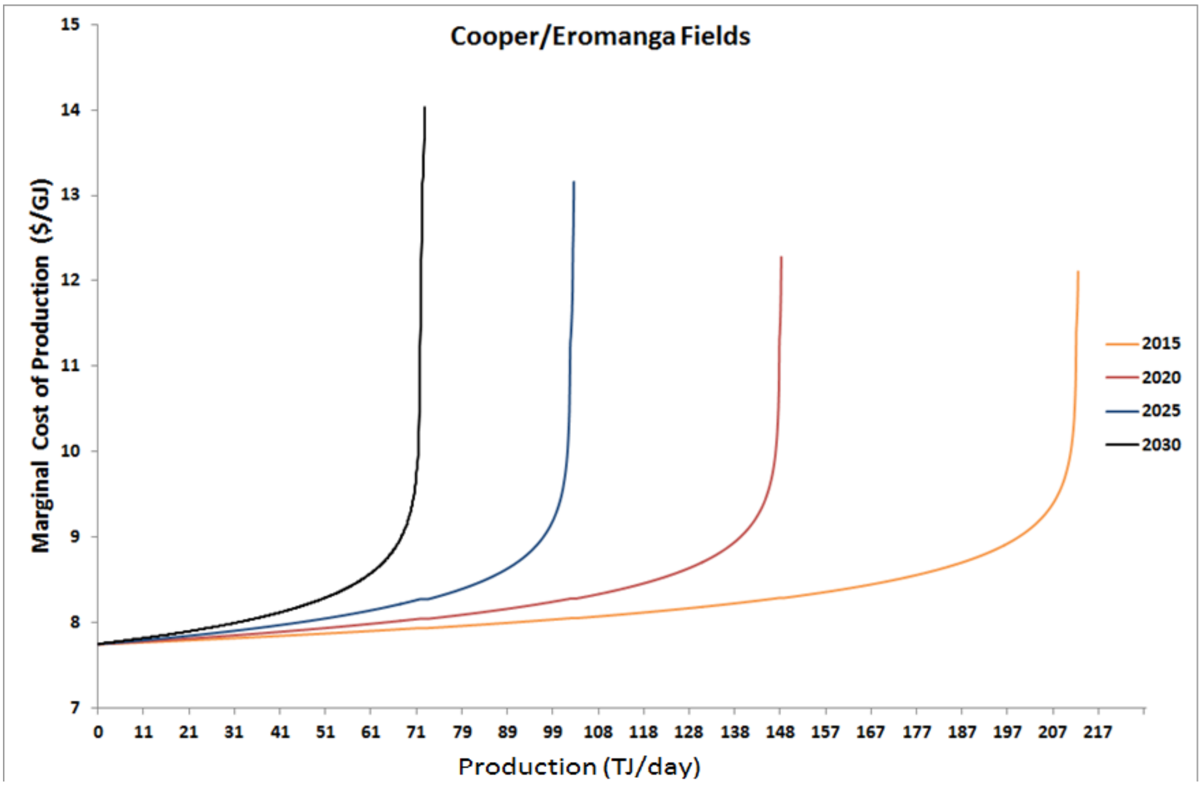

Figure 8: Cooper Eromanga/Golombek marginal cost of supply curve

Table 4: Golomobek Function Coefficients for Example Fields

Node	Roma	Spring Gully	Kogan
Field	Roma OA	ATP 592	Kogan East
A	3.35	4.70	3.01
B	0.061	0.0044	0.00108
Γ	-0.015	-0.00099	-0.003157

Processing capacity is sourced from AEMO's annual planning reports (GSOO [99, 100]), and it should also be noted that processing capacity is dealt with implicitly as an exogenous upper bound on production capacity. Thus, expansion timing and entry timing of processing plant is derived from AEMO [100].

Transport pipelines and the formation of the network topology has been derived from [99, 100], and more generally from [101]. The maximum flow capacity along each pipeline pathway within the network of nodes, is by necessity an exogenous input into the model. Contrary to the production and processing capacities, the dual of the utilization in network capacity is required for the model formation. Pipeline network expansion can also be implemented via scenarios for policy planning and analysis or with optimal expansion techniques discussed in André [110]. We present the main transmission pipelines which create the backbone of the network topology below in **Table 5**. A stylized version of the entire network topology for the EGM pipeline network is presented in **Figure 9**.

Table 5: Main Transmission Pipelines

Pipeline	Length (km)	Diameter (mm)	Owner	Tariff $/GJ	Forward Capacity	Backward Capacity
SW Qld Pipline	937	400	APA	0.85	385	360
Carpentaria Gas	840	450	APA	1.46	119	119
Roma-Brisbane	438	950	APA	1.01	232	232
Moomba-Sydney	1300	2200	APA	0.75	523	523
Moomba-Adelaide	1185	900	QIC	0.55	253	253
NSW-Vic	88	450	APA	0.78	92	128
SEA Pipeline	680	450	APA	0.7	314	314
SW Pipeline	202	500	APA	0.23	430	129
Vic-Tas	734	700	Palisade	2.00	130	0
Eastern-Aust	797	450	Jemena	1.16	288	288
Qld-GP	630	500	Jemena	0.90	142	142
Longford-Melb	174	1250	APA	0.24	965	130
Nth Qld Gas	393	254	Vic. Funds	0.51	50	0
Young-Wagga	131	450	APA	0.075	92	128
Melb-NSW-Vic	445	450	APA	0.99	71	500

4.1.1 Natural Gas Demand

The demand for natural gas by the LNG sector has been initially sourced from [71, 96, 100, 101, 103]. We assume that the required minimum capacity utilization rate for each of the proposed liquification facilities is set at 93% [111]. Furthermore, the timing of demand is a key variable, and is therefore considered in the scenario planning capability of this model. It should be noted that the demand is assumed to incorporate the losses associated with pipeline transport and liqification as is presented via the "as-produced" method in a similar fashion to the electricity sector [112, 113]. The timing of additional liquification plant trains to correspond to export demand, further developments in gas reserves and international demand, is also sourced from [100, 101].

The reference prices of demand for gas by the LNG sector is derived from the Free-on-board (Fob) netback equivalent price with respect to the Japanese hub Cargo-insurance-freight price (Cif). The derived Cif prices presented here for model calibration is sourced from the burner tip equivalent of the Japanese Crude Cocktail (JCC) price for oil translated into a gas price via the standard oil index linked S-curve [111, 113]. The demand curve, an iso-elastic non-linear function is represented with respect to our assumptions of quantity and reference price via the JCC/S-Curve pricing methodology [113].

The electricity generation sector is greatly affected by a shift in price and availability of natural gas [47]. As such, the future development of Gas fired Power Generation (GPG) is particularly sensitive to long-term prices and has had similar market integration issues when gas supply networks have been interconnected via international exports (e.g. Western Australia [111]). The demand for natural gas by GPG's has been sourced from [100]. Furthermore, technical specifications for each of these power stations is sourced from [42, 48, 49, 57, 58, 62, 63, 112, 114]. We calibrate the likely bounds of demand given historical operating capacities [42, 49], as a mid-point estimate. The upper and lower bounds for natural gas demand is derived from each GPG's installed capacity, heat rate (GJ/MWh), the type of operation (baseload, intermediate or peaking) and the technology type of the gas turbine (open or combined cycle), are all used to exogenously parameterize each power station.

The combined Mass Market/Light Industry sector historical and forecasts of demand for natural gas has been calculated from AEMO [100] and BREE [71, 96]. Historical prices at each of the corresponding nodes to AEMO's original network topology [99, 100] have been used to parametrize the iso-elastic inverse demand curve for the sector. Elasticities of demand have been sourced from the literature to further aid in the construction of this model [115-118]. We have chosen to represent the demand for natural gas in any node/market *m*, by applying a non-linear iso-elastic demand function which can be represented as follows:

$$D_m = D_m^O \left[\frac{P_m(D_m)}{P_m^O} \right]^{\sigma_m} \tag{3}$$

where D_m and $P_m(D_m)$ are the levels of demand and price at equilibrium, D_m^O and P_m^O are the reference (historical) demand and prices respectively in market m in 2013 [98]. The price elasticity of demand σ_m, for the three sectors in this model (GPG, LNG and MM/LI) is sourced from previous literature [117, 119, 120]. As mentioned earlier in this report, we shall neglect the full technical description of the market clearing conditions and algorithmic methods for simulating this market model and again refer the reader to [78].

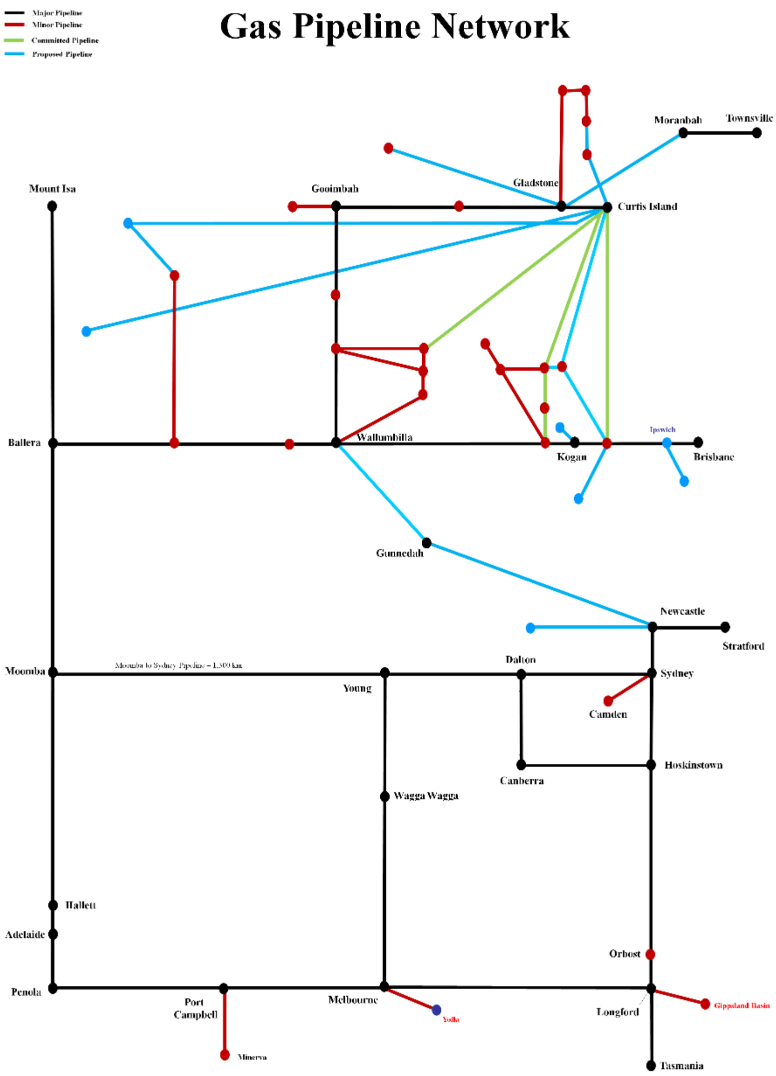

Figure 9: Stylized Network Diagram of the Eastern Australian Natural Gas Market

4.2 Base Case Simulation Results

The base case scenario presented here creates a comparative benchmark for future scenario development for policy analysis. This base case is largely used as a mechanism for parameter validation and as a proof of concept rather than a most likely case and should be viewed as such. Initially, we assume that the Japanese Cif price remains high, which corresponds to the medium scenario for global oil prices which reaches ~160/bbl in 2040 [121]. Demand for natural gas has been derived from the AEMO Gas statement of Opportunities (see [99, 100]). Electricity market generation behaviour has been derived from AEMO [42, 48, 49] and we further assume that entry timing and retirements are within the bounds of previously reported rates [47].

The LNG sector is assumed to have an investment and production profile that is largely derived from [99, 100]. Furthermore, we also assume that the entry of ARROW gas reserves will be delayed and the associated national supply and marginal cost curve is shifted to the left (see **Figure 10**). While this shift in the supply curve is dramatic, the resulting gas prices for the Eastern Australian capital cities are still somewhat in line with the expectations of AEMO and Core Energy's analysis [102, 103]. While world gas markets are now in turmoil given the current Saudi Arabian led OPEC over production of oil and gas, the world being awash with gas is still a somewhat interesting and important scenario to examine. The results presented in **Figure 11** and **Figure 12**, while not out of sample with AEMO [100], nor its counterpart Core Energy [103], estimate that prices will remain high. This base case mentioned here represents a proof of concept for the modelling platform and its integration with electricity market modelling.

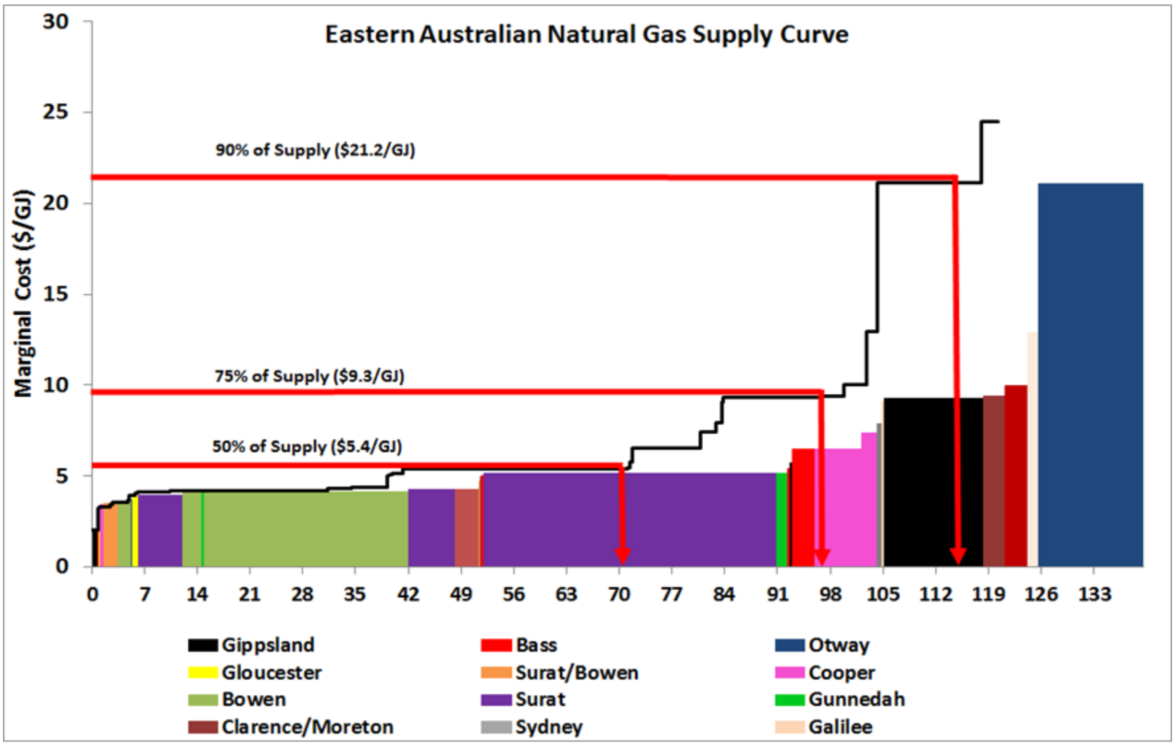

Figure 10: Marginal cost curve shift associated with a delay supply

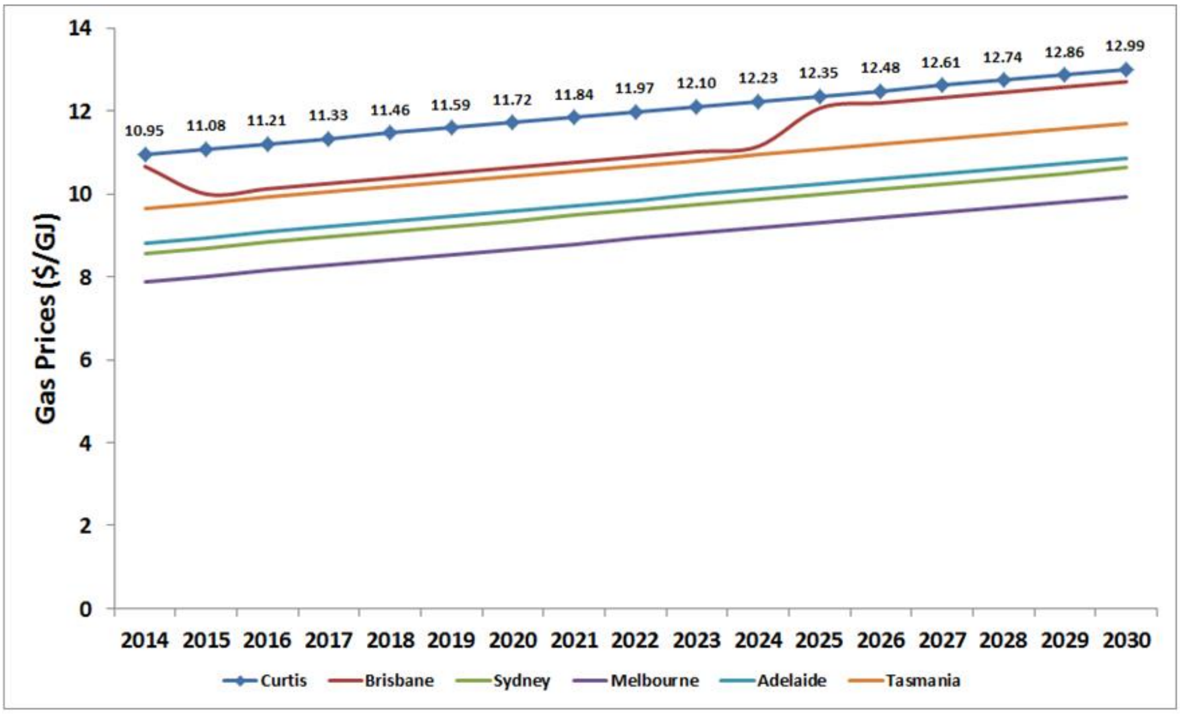

Figure 11: Natural Gas Spot Prices Base Case Scenario

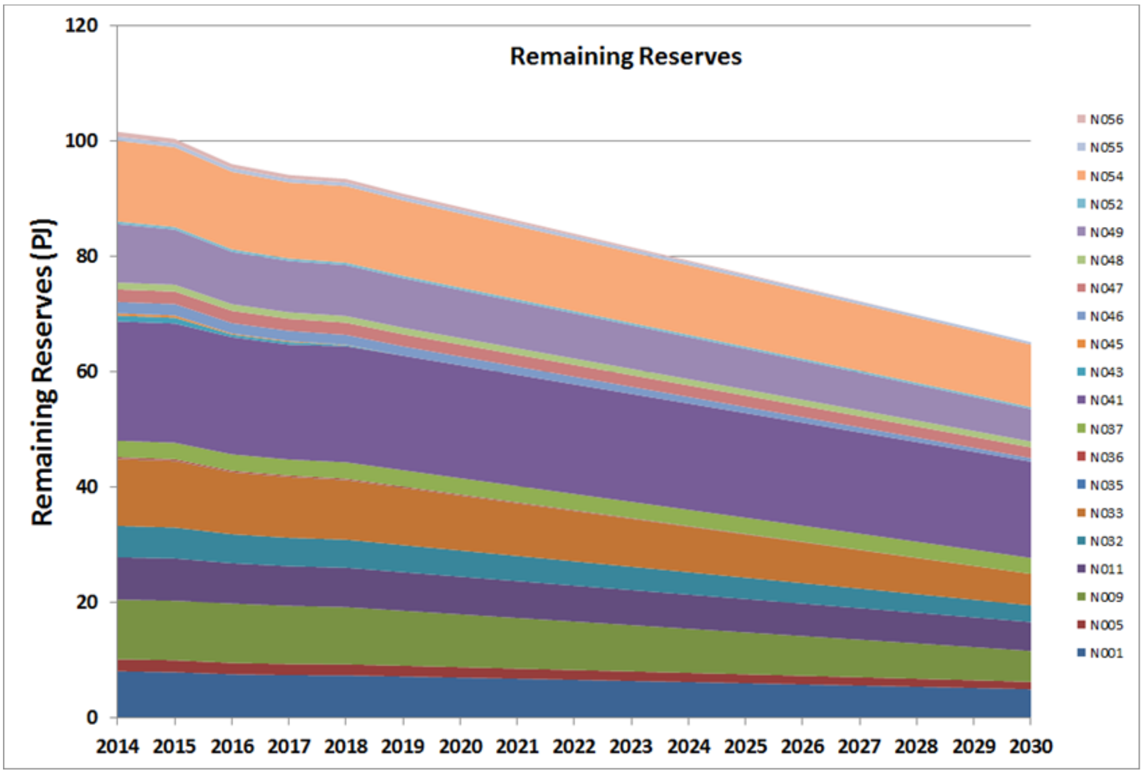

Figure 12: Supply node production schedule over time

5 Future Grid Scenario Modelling

In this section we will provide an overview of the scenario frameworks employed by Project 3 and the CSIRO Future Grid Cluster [50]. We will then provide a brief overview of the relationships between the CSIRO's Future Grid Forum (CFGF) Scenarios and how the cluster will proceed with its modelling. Furthermore, this report will largely focus on Project 3's modelling results for the **first** of the CFGF scenarios with an expanded sensitivity and parameter suite.

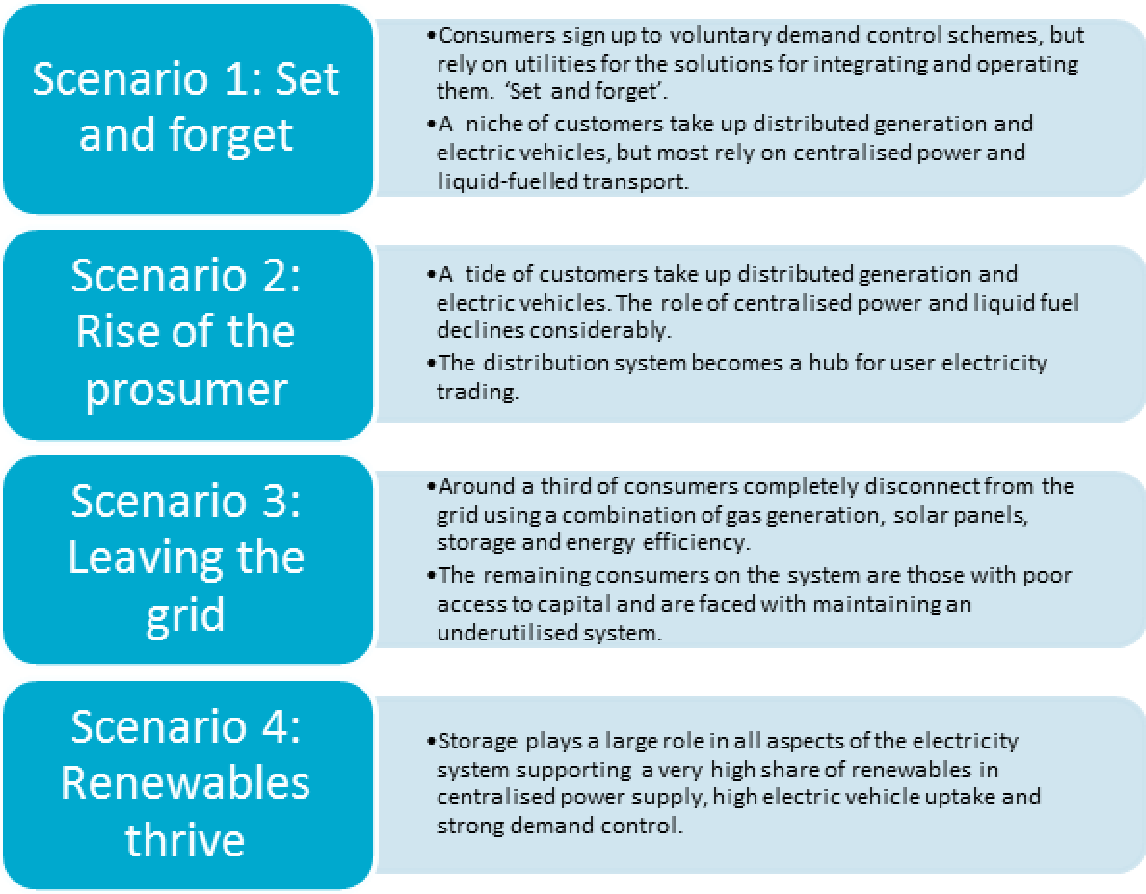

Figure 13: Future Grid Forum core scenarios [50]

Project 3 will reexamine and re-establish the CFGF scenarios from **first** principles and this reformulation will allow for the Future Grid Cluster projects to take into account a broader range of: **p**olicy/**r**egulatory; **e**conomic/**m**arket and technological influences. These **three** key system influencer categories are inextricably linked and therefore need to be modelled. Furthermore, these drivers are the cornerstone to scenario development and quite like a chain of influencers which will result in a transparent elucidation of the modelling assumptions.

Firstly, the key influencers were summarized into ten scenario kernel elements that are somewhat independent of each other. We then generate a set of "Reduced Scenarios" that can be used for discussion, scenario selection and external communication purposes. Secondly, scenarios are represented via all of their explicit sub-components which reflect the "micro" inputs which generate the parameter suite that needs to be modelled explicitly.

5.1 The four influences

The four categories of key influences and their inter-relationships are set out in this **S**ection and we provide a further overview of Project 3's scenario construction and integration with the CFGF.

1) Policy (and regulatory) decisions

- Actions in the policy and regulation space which are under the control of Australian policymakers and stakeholders
- Policy actions are orthogonal to states of the world
- Can depend on outcomes of states of the world
- Policy and regulatory decisions can be classified into either supply- or demand-side focused.

2) States of the World

- Forces or influences that are outside Australia's control are described here by the following three categories:
  a. Supply-side forces: These include changes in the parameters of key supply side technologies, such as technology costs and costs of fuel feed-stocks
  b. Demand-side forces, that are further divided into two sub-categories, those being:
     - Structural and behavioural, and
     - Technological development related
  c. International Forces which includes actions of markets and policy decisions by other countries.

3) Sensivities

Many policy and states of the world need to be modelled as having two or three outcomes. Some are binary (yes/no) and some are sensitivities with several states. We chose to limit sensitivities to **three** levels, that is, low, medium, and high (or slow, medium, and fast in the case of rate based parameters, such as technological learning). This limitation is imposed in order to limit the extent of the combinatorial explosion that arises when combining all the different possible outcomes.

4) Linkages

There are also interactions between the various forces and their sensitivities. In particular, it is important to note that there can be linkages within and between forces in the following two categories:

- States of the world
- Policy.

5.2 Scenario Kernels

In order to facilitate the communication of Project 3's modelling results for scenarios that are relevant to policy and investment decisions, we need to work at an appropriate level of detail. Since the Future Grid Cluster is only concerned with the impacts of policies and external forces on large-scale infrastructure investments and wholesale market behaviour, the kernel scenarios will be handled at this level. The structure for developing the Project 3 scenarios is shown in **Table 6.**

Table 6: Kernel elements

Kernel Element			States of the World		
Supply Side			Low/Slow	Medium	High/Fast
Technology costs and selection	Fossil Technology costs	1			
	Renewable/Zero emission Technology costs reduction	2			
Fossil Fuel Costs		3			
Climate policy	Carbon Pricing	4			
	Renewable Energy Target	5			
Electricity Demand			Decline	BAU	High
Energy Growth (GWh)		6			
Demand profile changes			Decrease	Status Quo	Increase
	Load Factor Change	7			
			-> Day	Status Quo	-> Night
	Day to Night Load peak shift	8			
Policy Support for renewable generation			Yes	No	
Transmission Super projects		9			
Scale Efficient Network Extensions		10			

The above table sets out the ten kernel elements grouped into three major categories: supply-side, demand-side, and policy support. It should be noted that there are eight elements with three sensitivities and a further two which have two sensitivities. This leads to a total of 26,244 possible combinations which are not easily manageable for without a methodology such as ours.

5.3 Scenario Planning: BAU/Counter Factual

Establishing a set of scenarios which examines the possible future given a set of prior assumptions is a difficult exercise [122-124]. The most common starting point for any investigation using the "Scenario Analysis" methodology [125, 126], is to create a counter-factual that may or may not represent our future expected states, but is used as a reference state for comparison [127].

This counterfactual in our case is used to create a well-defined rule based environment whose main value is to elucidate the current state of affairs in the electricity sector and to understand an idealised representation completely [46, 128]. While a very idealised picture of the electricity market may turn out to be an approximate and somewhat incomplete picture of the real world, its "valuefulness" lies in the construction of such a conceptual framework [128], as outlined in this report and the previous deliverables [129, 130]. Furthermore, due to recent policy volatility and an increasingly visible trend in the decline of electricity demand this scenario shouldn't be regarded as a "Business As Usual" case study. Furthermore, this methodology remains useful as a reference or counterfactual scenario against which other scenarios could be compared [125, 128, 130-132].

While this BAU/Counter Factual is mostly self-explanatory the broad aspects of this scenario are as follows:

- Demand for electricity is assumed to be increasing in terms of total annual energy (as generated) and with respect to peak demand.
- The shape of the load duration curve and load factors for each of the NEM states remains the same (as shown in the 2012 and 2014 AEMO NTNDPs' [42, 133]).
- Greenhouse gas (GHG) and Renewable Energy Target (RET) policies are both assumed to be with the moderate/medium carbon price trajectories and the previous RET (41 TWh at 2020 which equates to roughly 20% of all electricity generated).
- Technological costs, for conventional (combustion) and renewable energy generators have been sourced from a survey of the best available forecasts (i.e. from [42, 45, 50, 57-60, 134-136]).

The assumptions used to develop this BAU/Counter Factual scenario are presented in **Table 7** and were originally developed for a similar exercise by this project team [45, 137]. Following the broad overview presented in **Table 7** we will now provide the homoeomorphic mapping into the scenario kernel elements via

Table 8.

Table 7: BAU/Counter Factual Scenario Assumptions

Forces underpinning scenario	Long-term historic trend consumption growth
	No consumer reaction to rising prices
	Gas prices reflect global energy trends
	Climate change not an issue
	No recognition of technology shift to renewables and distributed generation
Capital costs (2035)	CCGT $1100/kW
	OCGT $1100/kW
	Wind $2558/kW
Network topology	Existing
Generation locations	Located close to transmission infrastructure
Modelling assumptions	Wind intermittent to 30% capacity factor
Fuel price (Moomba), (2035)	Medium Gas $8.32/GJ
	Low gas price $4.89/GJ
	High gas price $12/GJ

Table 8: BAU/Counter Factual Scenario Kernels

BAU/ Counter Factual					
Kernels		Kernel Element	States of the World		
Supply Side			Low/Slow	Medium	High/Fast
Technology costs and selection	Fossil Technology costs	1		X	
	Renewable/Zero emission Technology costs reduction	2		X	
Fossil Fuel Costs		3		X	
Climate policy	Carbon Pricing	4		X	
	Renewable Energy Target	5		X	
Electricity Demand			Decline	BAU	High
Energy Growth (GWh)		6		X	
Demand profile changes	Load Factor Change		Decrease	Status Quo	Increase
		7		X	
	Day to Night demand peak shift		-> Day	Status Quo	-> Night
		8		X	
Policy Support for renewable			Yes	No	

generation				
Transmission Super projects	9		X	
Scale Efficient Network Extensions	10		X	

5.4 Scenario Correspondence between CFGF and the Project 3 CFGC

The CFGF has taken a similar and somewhat related approach to developing its own scenario suite but has traversed a slight different path via its need to use detailed modelling levers. This has translated into a modelling and simulation input based approach. Furthermore, the scope and scale of the CFGF had the additional requirement of examining distribution system investment due to expansion, asset replacement and end-user pricing impacts and for the potential for changing elasticities in demand.

The CFGF scenarios have been constructed via three differentiators:

- Centralised generation versus distributed generation
- Significance of peak demand growth and the flattening (skewness) of the load profile
- Deployment of large scale renewable energy generation projects.

These differentiators are represented within this projects' scenario modelling framework, while also incorporating the relationships between the scenario Kernels (as illustrated in **Table 9**). Furthermore, the CFGF scenario drivers are shown in **Table 10** below.

Below in **Table 9**, the relationship between this projects methodology of using supply- and demand-side based drivers, and the CFGF scenarios is shown. Given that there are a variety of ways that drivers can be classified, we have used a mapping matrix as a guide to translating between the two slightly different approaches. As we have reported previously [129, 130], for example, we break the growth of distributed generation (DG) impacts into three components which then become drivers for the modelling scenarios: energy efficiency; and load profile changes of two kinds, load factor changes; and shifts of the peak to different times of the day. While this matrix is not exhaustive, experience is needed to transform the input data into inputs using our framework. We have done this in Project 3 by setting up the assumptions database. Also note that the CFGF's energy efficiency driver also maps to the same three drivers in our framework as it can influence all of the above to varying degrees.

5.5 Representing the Scenarios for the CSIRO Future Grid Cluster

The CSIRO Future Grid Scenarios have to be transformed and unbundled to suit communication between the diverse modelling frameworks/tools that are used by the different projects in the Cluster. It should be further noted that without an *explicit* specification of how the CSIRO scenarios are related to specific scenario settings/switches it will become increasingly difficult to ensure that each project in the Cluster are using the same scenario parameters assumptions, inputs or drivers.

The key differences between the framework presented here and the previous deliverable to the Future Grid Forum's representation of the scenarios is that we identify the:

1. **Distinction between supply- and demand-side drivers**.
   - No explicit delineation between supply- and demand-side drivers
     - Future Grid Cluster is focussed on transmission level models and effects.
     - Project 3 will not be explicitly modelling the costs and impacts of various battery storage scenarios or retail tariff innovations.
       - Project 1 will be examining these aspects of the Distribution system.
     - These will be modelled for by including them as externalities through using the different load growth and load shape scenarios sourced from the CSIRO FGF.
2. **Differentiation between controllable and uncontrollable drivers**.
   - FGF scenarios have no explicit distinction made between controllable and uncontrollable drivers.
   - Examples such as:
     - Carbon pricing policies and developments of new customer pricing frameworks or;
     - States of the World and include variables such as natural gas prices or technology costs.

The reduced scenario representation is an extremely useful tool in order to communicate results and to identify and map the CFGF scenarios to the FGC scenarios controllable and uncontrollable drivers. In **Table 11** we have detailed these linkages and demonstrate how all scenarios (CFGF and FGC) are classified according to both the supply- and demand-side and according to the controllability of these by Australian policy makers.

Table 9: Project 3 and CSIRO Future Grid Forum Scenarios

CSIRO Future Grid Forum Scenarios / **Project 3 Scenarios**			*DG Share*	*EV Uptake*	*Demand Response (Storage)*	*Demand Response HVAC)*	*Demand Response industrial)*	*Disconnections*	*GHG reduction commitment*	*Technology Costs*	*Energy Efficiency*	*Network*	*Gas prices*	*Customer Pricing Framework*	*Large Scale Renewables*
Kernels															
Supply Side		**Kernel Element**													
Technology costs and selection	Fossil Technology costs	**1**								**X**					
	Renewable/Zero emission Technology costs reduction	***2***								**X**					
Fossil Fuel Costs		***3***											**X**		
Climate policy	Carbon Pricing	***4***							**X**						
	Renewable Energy Target	***5***							**X**						**X**
Demand Side															
Energy Growth (GWh)		***6***	**X**	**X**				**X**			**X**	**X**		**X**	
Demand profile changes	Load Factor Change	***7***	**X**	**X**	**X**	**X**	**X**	**X**			**X**			**X**	
	Day to Night demand peak shift	***8***	**X**	**X**	**X**	**X**	**X**				**X**			**X**	
Policy Support for renewable generation															
Transmission Super projects		***9***													
Scale Efficient Network Extensions		***10***													

Table 10: CFGF Scenarios and drivers[1]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
DG share	Low	High	High	High
EV uptake	Modest Managed charge profile	Medium-high Managed charge profile	Medium-high Absent charge profile	High Managed charge profile
Demand response (storage)	Equivalent to Resi. 1kW for 5 hours 0-20% 2015-2030 but centrally located in suburb	Resi. 1kW for 5 hours 0-20% 2015-2030 In individual homes	Used off-grid. 5kW batteries plus 2.2kW diesel back-up	Resi. 1kW for 5 hours 0-20% 2015-2030 In individual homes
Demand response (HVAC)	Both resi. and comm. managed	Both resi. and comm. managed	Unmanaged, remaining customers can't afford upfront costs	Both resi. and comm. managed
Demand response (Industrial)	Managed	Managed	Unmanaged, remaining customers can't afford actions	Managed
Disconnections	RAPS only	RAPS only	All existing and new DG owners by 2020	RAPS only
GHG reduction commitment	Moderate carbon price	Moderate carbon price	Moderate carbon price	Moderate carbon price plus extended RET to 100%
Technology costs	AETA projections for CG, CSIRO for DG, storage, large scale solar PV	AETA projections for CG, CSIRO for DG, storage, large scale solar PV	AETA projections for CG, CSIRO for DG, storage, large scale solar PV	Accelerated based on stronger global abatement commitment
Energy efficiency	AEMO moderate growth case based on current price pressures	AEMO moderate growth case based on current price pressures	Low energy consumption due to relatively higher costs for those left on grid	Low energy consumption based on expected higher prices due to lower emissions
Network	Modest expansion. Load factor maintained	Flat. Significant decline in load factor	Flat. Significant decline in load factor	Load factor declining. Expansion to connect renewables
Gas price assumption	AETA medium	AETA low supporting gas on-site generation	AETA low supporting gas on-site generation	AETA medium
Customer pricing framework	Cost reflective supporting engagement	Cost reflective supporting engagement	Non-cost reflective encouraging disconnection	Cost reflective supporting engagement
Large scale renewables	Substantial but some technologies limited by cost of back-up	Substantial but some technologies limited by cost of back-up	Substantial but some technologies limited by cost of back-up	Very high supported by storage and lower costs

[1] CSIRO Future Grid Forum – "Modeling The Future Grid Forum Scenarios", Table 3, page 18.

Table 11: CSIRO Future Grid Forum and the Cluster Project 3 Scenario drivers

		Controllable Drivers	Uncontrollable Drivers
Cluster Project 3	Supply Side	Climate policy Carbon Pricing Renewable Energy Target Transmission Super projects / Super grids Scale Efficient Network Extensions	Technology costs (Affected by overseas policies) Fossil Fuel Costs (Affected by overseas policies)
	Demand Side	Energy Efficiency	Electricity Demand Energy Growth (Annual Energy) Demand Profile Change (Inc. Peak Demand growth/decline)
CSIRO FGF	Supply Side	GHG reduction commitment Large scale renewables	Technology Costs Gas price assumptions
	Demand Side	Network (Investment/price regulation) Customer Pricing Framework Reform (CSIRO FGF) EV Uptake (With managed charging) Demand Response (HVAC) Demand Response (industrial)	Energy Efficiency Disconnections DG Share Demand Response (Storage)

5.6 Scenario 1: "Set and Forget"

This section will set out the first scenario "Scenario 1: Set and Forget" and show how the FGC will endeavour to model this possible policy and supply- and demand-side agent behavioural approach. Initially we will set out four tables which show how the CFGF Scenarios will translate into the reduced scenario framework. With these tables, we will show not only how the mapping unfolds (a homeomorphic mapping), but also how each of the kernel/driver settings shown in Table 10 will translate into the sensitivities required by Project 3 for its reduced scenario representation. In each of the tables the controllable policy drivers have been coloured in orange text while the others in black are seen to be uncontrollable. While the distinction between supply- and demand-side drivers may not appear to be very clear, we have highlighted the demand related ones in light green (see Table 12 to Table ***16***). Furthermore, it should be noted that we have endeavored to maintain the order of the drivers/policy to facilitate comparisons between FGF and the CFGF derived from [50]. This initial modelling was conducted over the planning horizon 2016-2045 (30 years). It should be further noted that the future modelling undertaken by this project will have a longer horizon out to 2050.

5.6.1 Assumptions and Data for Scenario 1

We shall now provide a brief overview of the data requirements, broad policy and market characteristics that are used to formulate this scenario within out electricity market simulation platform PLEXOS.

Electricity market investigation should factor in expected consumer behaviour. It is anticipated that in this scenario, the current policy drivers and conditions would indicate that consumers are subject to the full cost reflective pricing framework which will support and facilitate engagement [50].

Consumer responsiveness mechanisms such as reduced demand (Demand Side Management DSM) is also relatively moderate and controlled via the DNSP. This mechanisms sensitivity is largely consistent with the analysis of AEMO's 2014 NTNDP [42] and their prior investigations into DSM roll out [49, 138]. The ability of consumers to respond to electricity market conditions is mainly driven via the implementation of battery storage options within the distribution network system. Individual consumer uptake of storage is somewhat limited and is controlled centrally via the Distributional Network Service Provider (DNSP) (in a similar fashion to [45] and [46]). The rate of consumer and more generally appliance efficiency rates [139, 140], are assumed to be relatively modest and are consistent with the assumptions used by the CFGF modelling [50] and AEMO [42].

The increase in distributed generation in the electricity sector is relatively modest as is its impact on demand. While in this scenario consumer action and potential disconnection is somewhat avoided, the need for such action is somewhat nullified by the centralised control of DG and storage options. Furthermore, the rate of disconnection amongst all consumer types (industrial, commercial and residential) is limited to locational characteristics of those consumers. It is envisaged that disconnections are therefore limited to consumers who are located in remote areas (i.e. Remote Area Power Systems, RAPS).

Electric Vehicle (EV) deployment is also fairly modest with no appreciable effects from uncontrolled charging. Furthermore, controlled charging is broadly implemented and as such has a lower impact on peak electricity demand [55]. While EV and Plug-in Hybrid Electric Vehicle (PHEV) deployment rates are modest it assumed that the world oil price will remain within the moderate estimates of the EIA and IEA [121, 141]. This medium/moderate price range estimate (≥$150/bbl by 2020), will in turn have a curtailment effect on the uptake of this technology within certain consumer group types, who are more motivated by environmental concerns over the cost of fuel for transportation.

The technological costs associated with generation technologies have been sourced from the latest data and methods [42, 49, 136]. We will also provide in **Table 17** (also we present in **Figure 16** and **Figure 17** the key years in our planning horizon graphically), a summary of the costs used in this initial modelling. These data represent the "Medium" technology cost projections for construction and connection in NSW (primarily the North-Central transmission zone, NCEN) from the 2014 AEMO NTNDP [42]. The deployment of renewable electricity generation options may be in fact substantial however ,the cost of backup may then limit the types of technologies which are likely to be deployed [50, 142]. However, this may be the case in this anticipated state of the world, the costs of back-up and more generally within the distribution network could still have an impact [143]. The GHG abatement target and pricing has been sourced from the Australian Government's original commitment of 5% by 2020 with respect to 2000 levels. The forward carbon price projection has been provided by AEMO and the Australian Treasury [43].

The expansion of the NEM transmission network in this scenario is assumed to be relatively modest. Transmission expansion needs which could be required due the large scale deployment of renewable generation are in line with those of AEMO NTNDP [42] and CFGC [50, 142]. Therefore, the need for transmission network super projects is unlikely given the expected generation investment schedule and the likely demand projections.

5.6.2 Fuel Price Projections

Scenario 1 will use the medium black and brown coal forecasts from the recent 2014 AEMO NTNDP [42] as its initial benchmark price (see **Figure 14)**. While the internationalisation of coal from Australia has yet to make an appreciable impact on domestic black coal prices, Hunter Valley coal producers may make the decision to export their coal in the future. This possibility is left for future research.

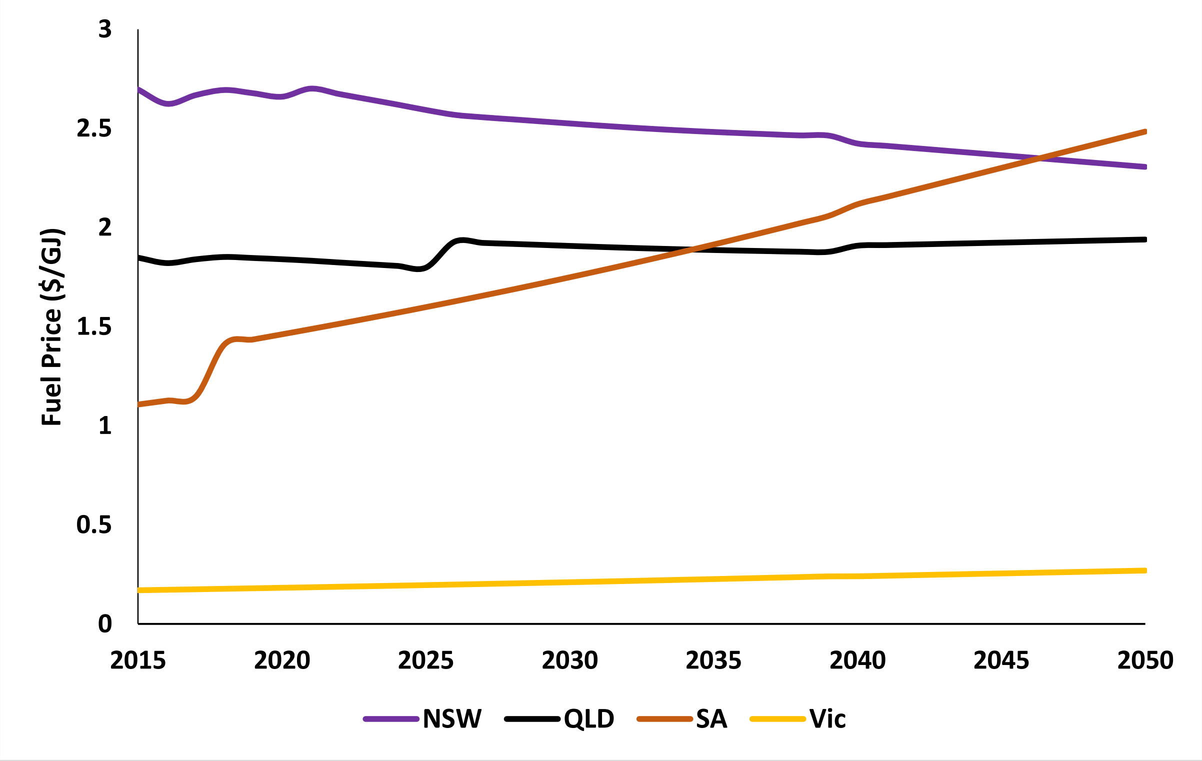

Figure 14: Projected Coal Prices (Medium Forecast)

As we have discussed earlier, this project has developed an integrated gas modelling framework (see section 4 above) and the price forecast which we have relied on here is the Low case scenario (see **Figure 11**). Furthermore, the gas forecast presented earlier in this report diverges with the expectations of forward prices present by the CFGC [50] by at least 30-50% and those presented in [71, 100, 144], due not only to the methodological differences but also with respect to the assumed international market conditions. It should be noted that since that our initial modelling, natural gas prices have been suppressed by Saudi Arabian oil production increases which have flowed onto the Japanese and consequentially, Australian natural gas markets due to their linkage with oil [145].

5.6.3 Demand Projections

This first scenario uses the AEMO 2014 [42], medium electricity demand forecast (see **Figure 15**), which has the following endogenised characteristics: moderate adoption of embedded generation options; high adoption of peak load shaving technology deployment, and; conservative EV and PHEV deployment.

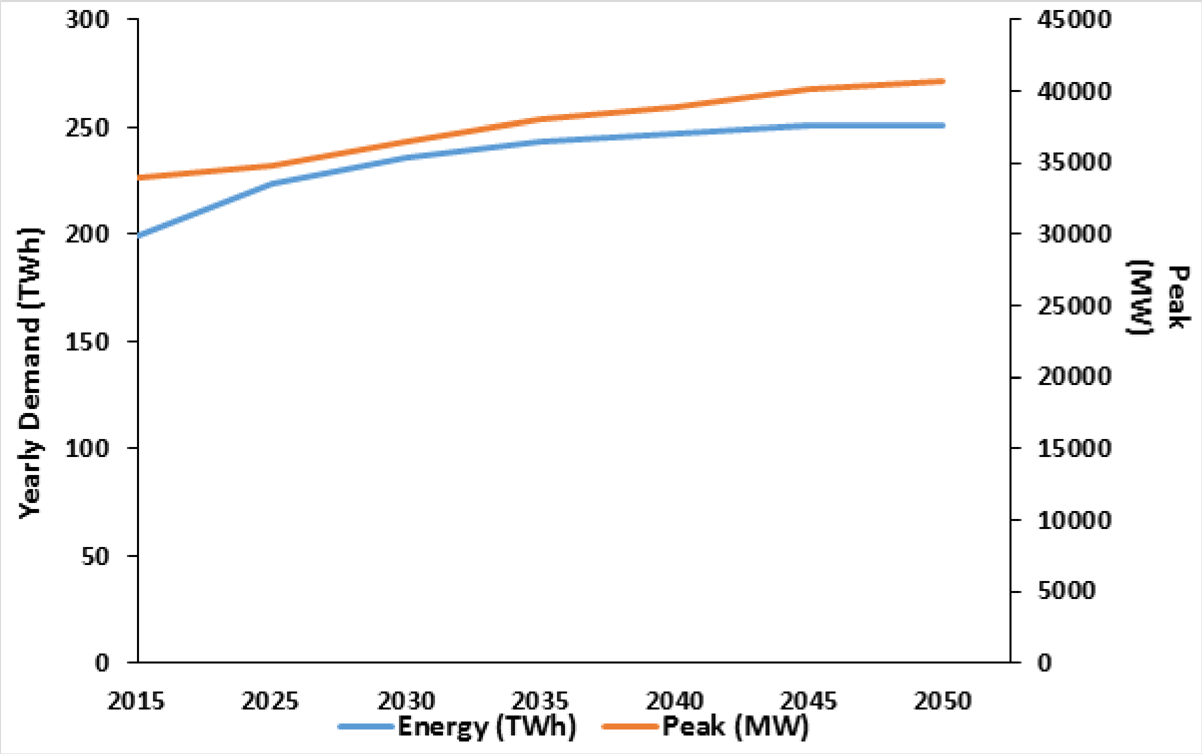

Figure 15: NEM Demand Projections for Scenario 1

Table 12: Mapping of the CSIRO Future Grid Forum “Set and Forget” Scenario to Project 3 Scenario Framework

CSIRO FGF Scenario 1

Kernels		Kernel Element	Sensitivities			DG Share	EV Uptake	Demand Response (Storage)	Demand Response HVAC)	Demand Response industrial)	Disconnections	GHG reduction commitment	Technology Costs	Energy Efficiency	Network	Gas prices	Customer Pricing Framework	Large Scale Renew
Supply Side			Low/Slow	Medium	High/Fast	Low	Med Mnged	Med	Med Mnged	Med Mnged	RAPS <=> None	Carbon Med	Tech Costs Med	Energy Growth	Through Price Elast	Medium	Cost Reflective	Medium
Technology costs and selection	Fossil Technology costs	*1*		X									Medium					
	Renewable/Zero emission Technology costs reduction	*2*		X									Medium					
Fossil Fuel Costs		*3*		X												Medium		
Climate policy	Carbon Pricing	*4*		X								Medium						
	Renewable Energy Target	*5*		X								Medium						Medium
Electricity Demand			**Decline**	**BAU =** ***Approx Flat***	**Growth**													
Energy Growth (GWh)		*6*	**Grow to '41 -> Decline**			Grow to 2041 -> Decline		N/A	N/A	N/A	Flt Impct	Flt Impact		BAU	??*	Flt Impact	Flt Impact	No elast Impact
Demand profile changes	Load Factor Change		**Decrease**	**Status Quo**	**Increase**													
		7		~X		Status Quo					Flt Impct*	Flat concave						
	Day to Night demand peak shift		**To Day**	**Status Quo**	**To Night**													
		8		X		Status Quo					N/A	No additional Impact						
Policy Support for renewable generation			**Yes**	**No**														
Transmission Superprojects / Supergrids		*9*		X								No						
Scale Efficient Network Extensions		*10*		X								No - Check with CSIRO						

Future Grid Forum - Scenario 1

*Unclear to what extent network investment translates to energy demand impacts through average pricing increases in CSIRO model

Table 13: Representation of the CSIRO Future Grid Forum Scenario 1 Domestic Policy

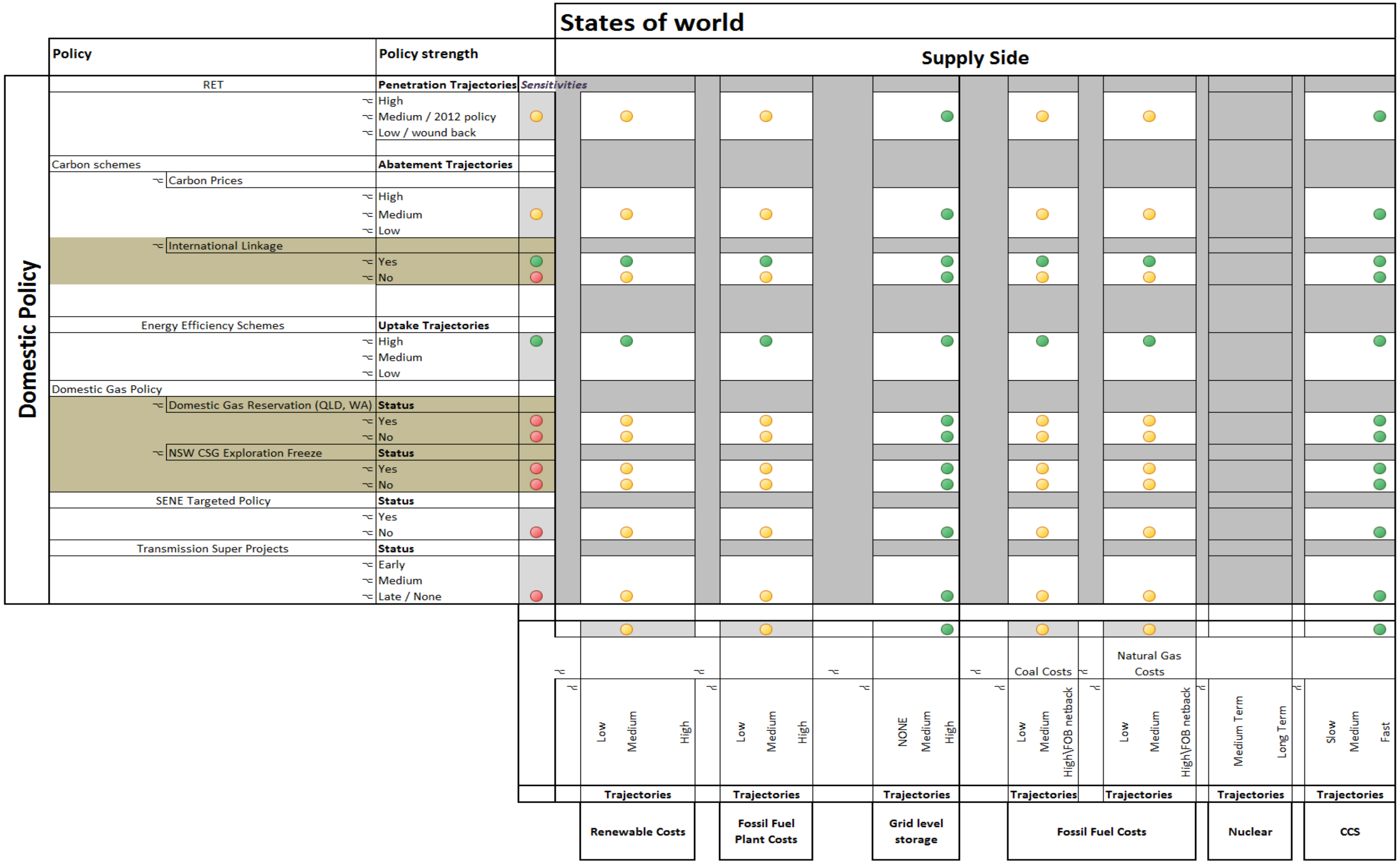

Table 14: Representation of the CSIRO Future Grid Forum Scenario 1 International Forces

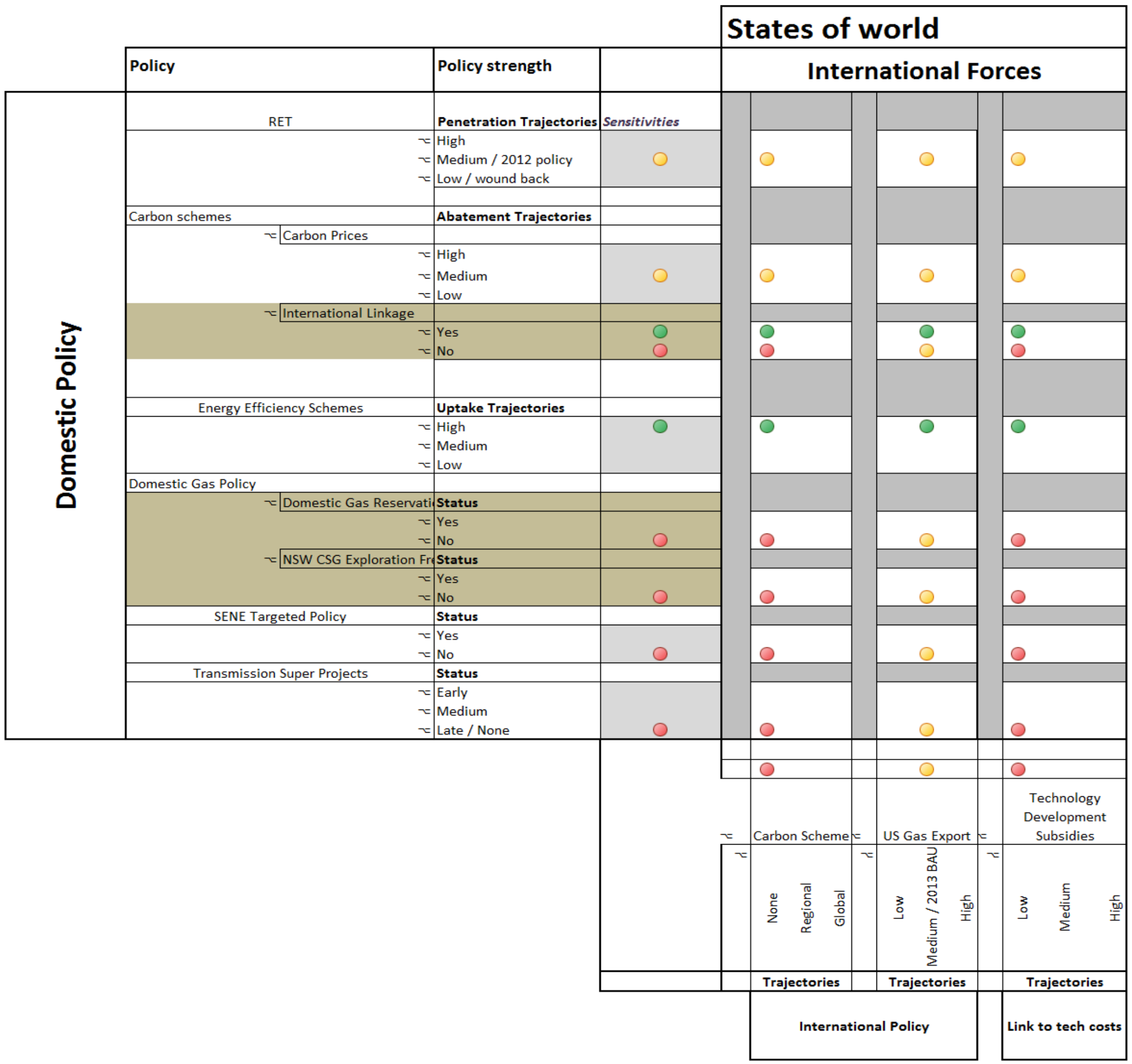

Table 15: Representation of the CSIRO Future Grid Forum Scenario 1 Demand Side Forces

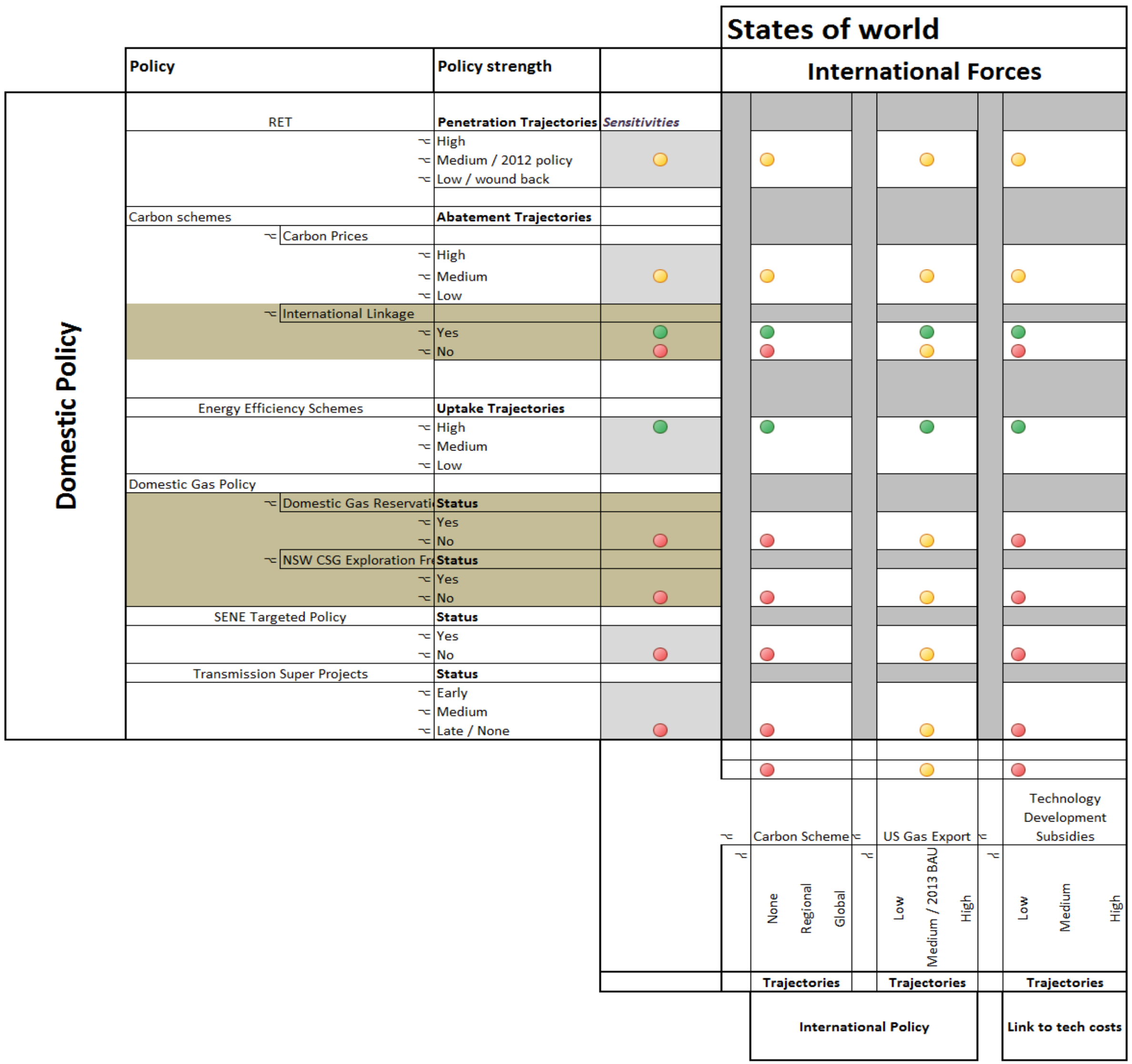

Table 16: Representation of the CSIRO Future Grid Forum Scenario 1 Technological Development

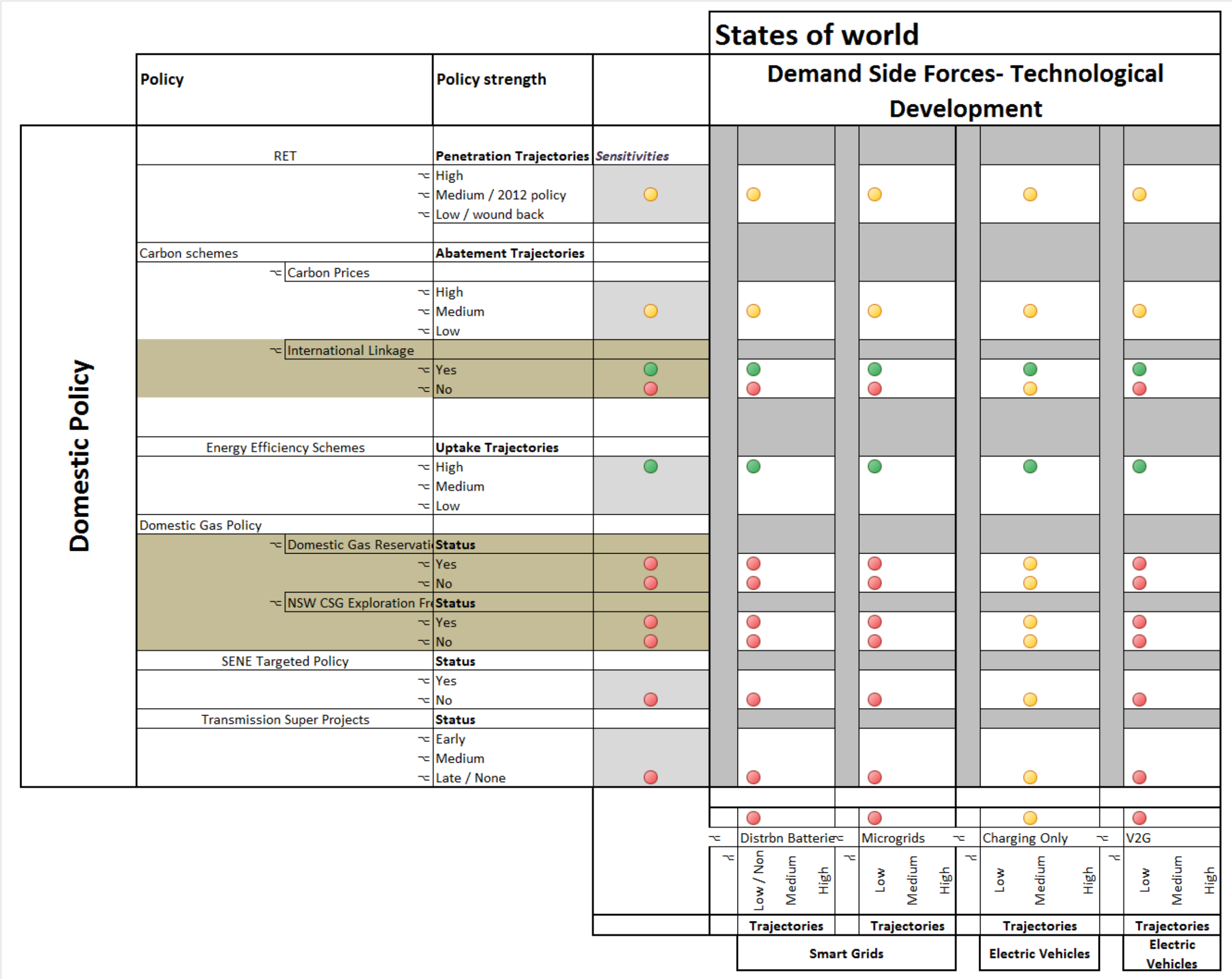

Table 17: Electricity Generation Technology Costs (Summary Based on NSW Capital Cost Estimates Real 2010 AUD)

	Build Cost 2020			Build Cost 2025			Build Cost 2030			Build Cost 2035			Build Cost 2040		
	Low	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**
Biomass	4994	5148	5163	4967	5131	5140	4984	5162	5171	5032	5229	5248	5077	5298	5331
Solar PV DAT	4026	4065	4067	3984	4029	4017	3998	4052	4043	4073	4147	4155	4151	4254	4288
Solar PV FFP	2518	2542	2544	2502	2530	2523	2511	2544	2539	2557	2603	2608	2606	2669	2690
Solar PV SAT	3090	3120	3121	3064	3098	3089	3075	3116	3109	3132	3189	3195	3192	3270	3296
Solar Thermal CLF	4517	4585	4591	4460	4531	4528	4467	4549	4547	4545	4648	4662	4631	4763	4803
Solar Thermal CR WS	6689	6789	6798	6591	6698	6692	6601	6723	6721	6717	6871	6892	6846	7043	7102
Solar Thermal PT WS	9094	9219	9241	8940	9072	9072	8943	9093	9098	9089	9281	9318	9253	9502	9591
Geothermal EGS	10493	12083	12738	10346	12982	14161	10056	13589	15341	10007	13604	15430	10007	13604	15430
Geothermal HSA	6984	7942	8338	6935	8574	9310	6783	9011	10123	6761	9037	10200	6761	9037	10200
ISCC	2272	2302	2308	2204	2235	2236	2171	2205	2206	2162	2204	2212	2160	2214	2235
OCGT	862	868	867	848	855	852	849	856	858	860	873	874	872	890	897
Pumped Hydro	3161	3259	3275	3165	3270	3282	3305	3317	3191	3233	3359	3376	3410	3434	3270
CCGT	1214	1230	1234	1199	1216	1217	1200	1219	1221	1212	1236	1242	1224	1255	1266
CCGT CCS	3205	3240	3243	3155	3193	3189	3157	3198	3201	3193	3253	3262	3230	3310	3339
Coal SC	2998	3057	3071	2929	2989	2998	2894	2958	2967	2881	2955	2970	2875	2962	2989
Coal SC CCS	5407	5527	5553	5280	5403	5420	5211	5343	5359	5180	5329	5358	5165	5336	5384
Wind	2791	2816	2817	2757	2779	2786	2747	2768	2776	2818	2868	2873	2872	2940	2964

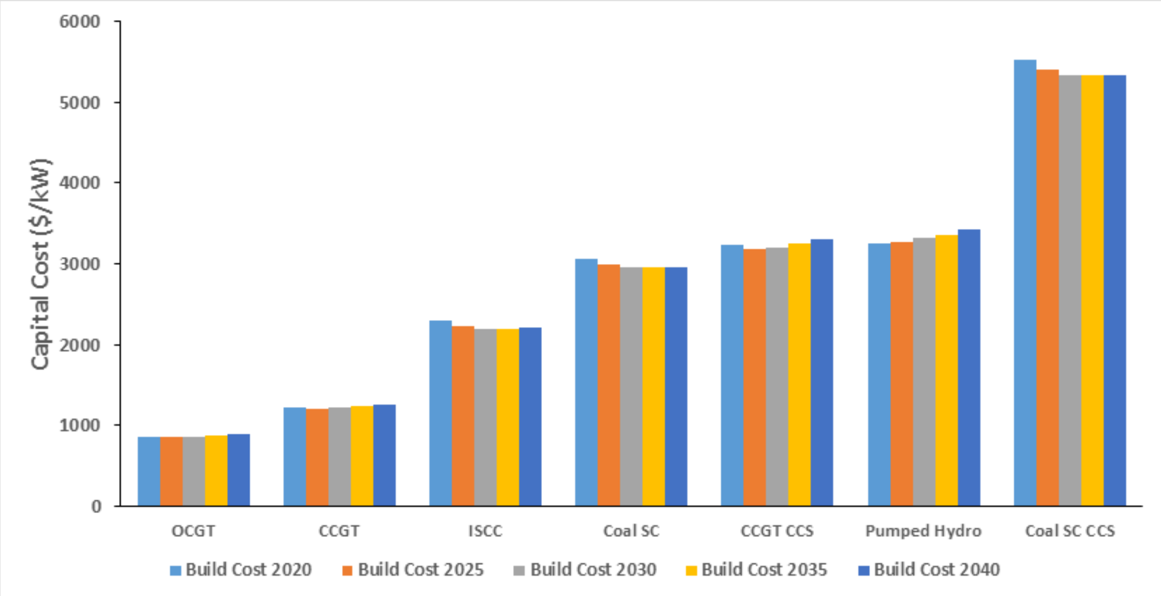

Figure 16: Technology Costs for Conventional Electricity Generation

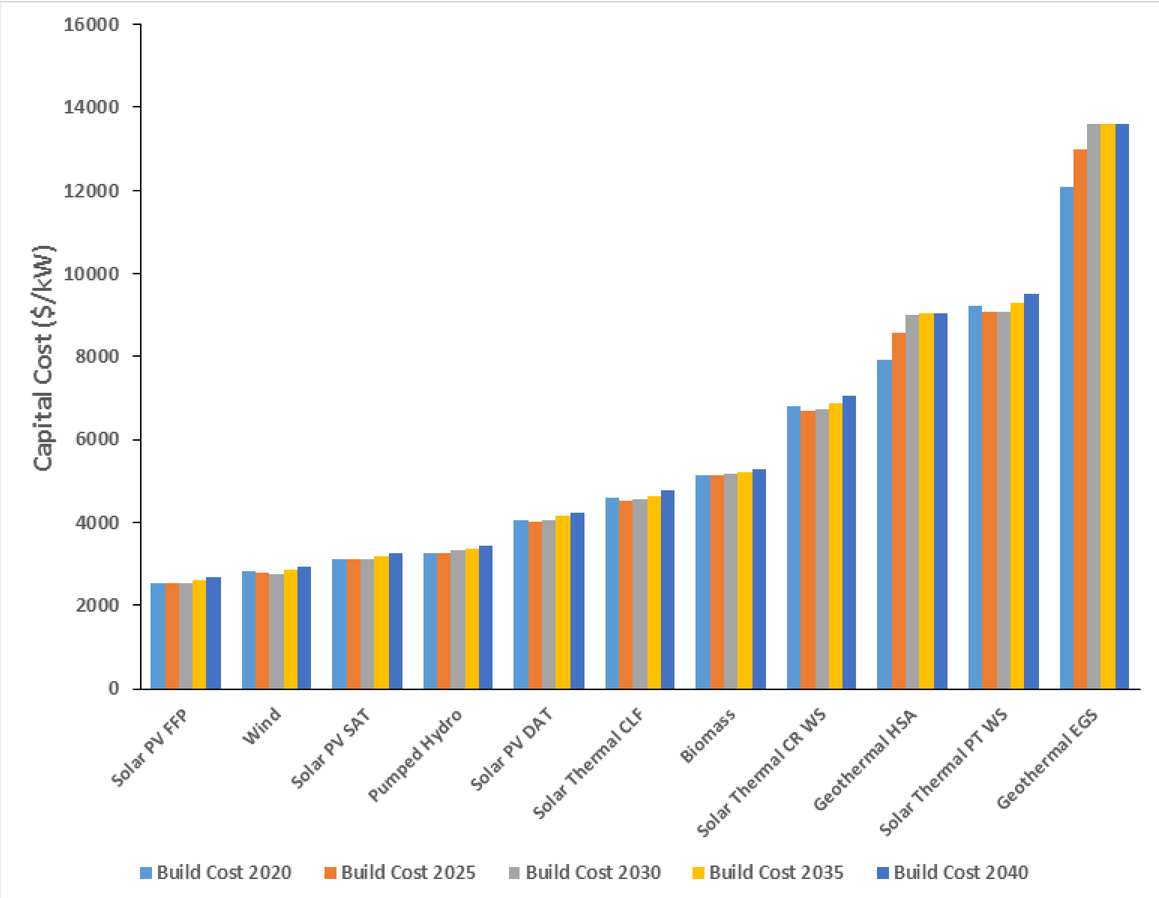

Figure 17: Technology Costs for Renewable Electricity Generation

5.7 Initial Modelling Results

This first set of results (Scenario 1a) provides us with an initial wholesale and market formation results surrounding the dynamic interplay between input fuel prices and their pass through. While policy imperatives are implemented with the minimum generation target of 33TWh for renewables are more than met by this version of the “Set and Forget” case [50], there are some other interesting aspects to consider.

As previously discussed, this scenario is somewhat similar in its assumptions and implementation, it will purposefully diverge from those presented by the CFGC in that renewable energy deployment and generation is hampered by prevailing long term gas prices. A LNG-glut [146] has grasped the worlds floating gas market and structural change is imminent. The suppressed LNG price and its linkage via the Japanese (CiF) market could have a noticeably significant effect on the viability of renewables within the foreseeable future.

While this projection of input fuel prices may have led to the suppression new solar and wind generation capacity, the likelihood of this type of structural change continuing over the life of the full projection is low. Furthermore, it should also be noted that while LNG and as a consequence the post-export linked Australian domestic gas prices are lower than had previously been foreseen, the volatility of gas prices is quite likely to continue.

5.7.1 Wholesale market spot prices

The spot market prices observed via out modelling frame present a significant uplift in wholesale price on top of the expected increase due to carbon pricing. Although, the explicit removal of a fixed carbon price has been implemented via a shift in Australian government policy, its inclusion post 2020 given the expectation of global action has been assumed. The spot prices observed in **Figure 18**, represent a four-fold increase in regional prices by comparison to similar modelling undertaken by the CFGC. This is largely attributed to shifts in government climate change and renewable energy policy since 2013 [147].

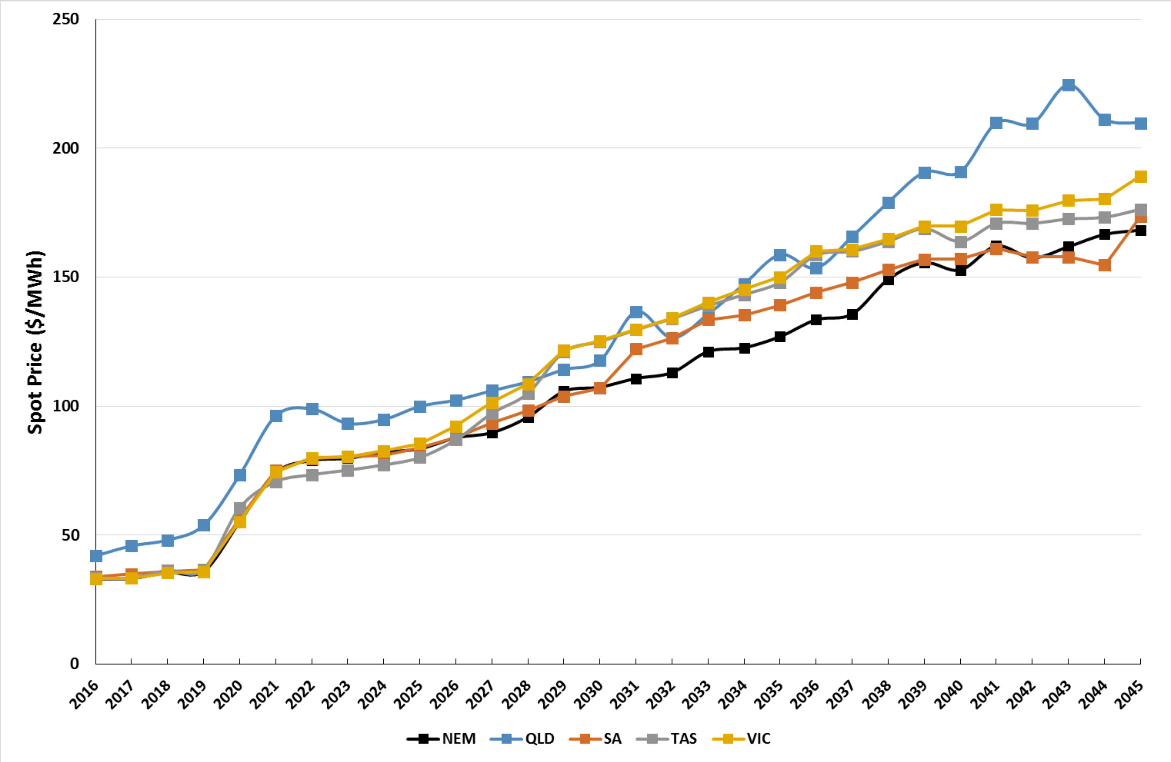

Figure 18: Yearly wholesale electricity market spot prices (Load Weighted Average)

5.7.2 Generation Profile

The presence of a somewhat altered renewable energy target and the removal of forced retirements in the electricity market for older and less efficient units in the generation fleet also produce alarming results. It is fairly evident, as demonstrated by the results presented in **Figure 19** that the continued presence of combustive generation types reliant on black coal are still producing more than 50% (see **Figure 20**) of the required sent out energy in the NEM. Similarly, the retirement of brown coal generation assets during the modelling period is seen to be modest and the introduction of low carbon prices following 2020 is ineffectual in reducing their influence on the NEM. It should also be noted that all invested in new gas generation plant within this initial set of modelling results has been exclusively OCGT. This is almost exclusively due to the expected high degree of uncertainty surrounding natural gas prices (as discussed above). However, changing global oil price conditions have in fact severely suppressed the gas prices presented previously and change the likely mix of investment in generation.

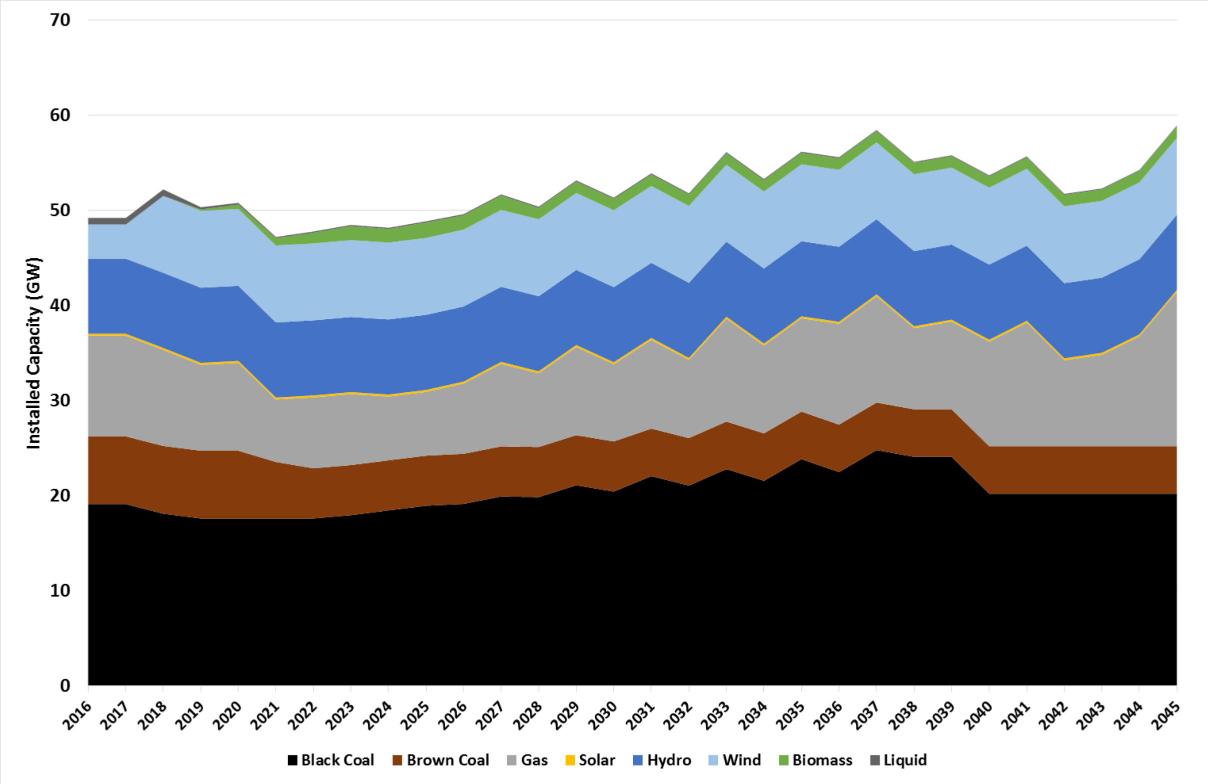

Figure 19: Installed Capacity by technology type for Scenario 1

The presence of "Installed" capacity for renewable energy generation is expected to comprise in excess of 30% of all installed generation capacity on the NEM by 2045 (see **Figure 21**). While each technology type has varying rates of availability, the presence/deployment of renewable generation would indicate that this is only a marginal increase of these technologies post 2016 levels.

While installed capacity would seem to make a somewhat of an impact, the rate of dispatch and availability as a percentage of total generation, is unlikely to rise above 20% (see **Figure 22**). We have also included a black line on the aforementioned figure as an indication of how the new target of 33TWh/year would appear contribute to overall moderate demand by 2045.

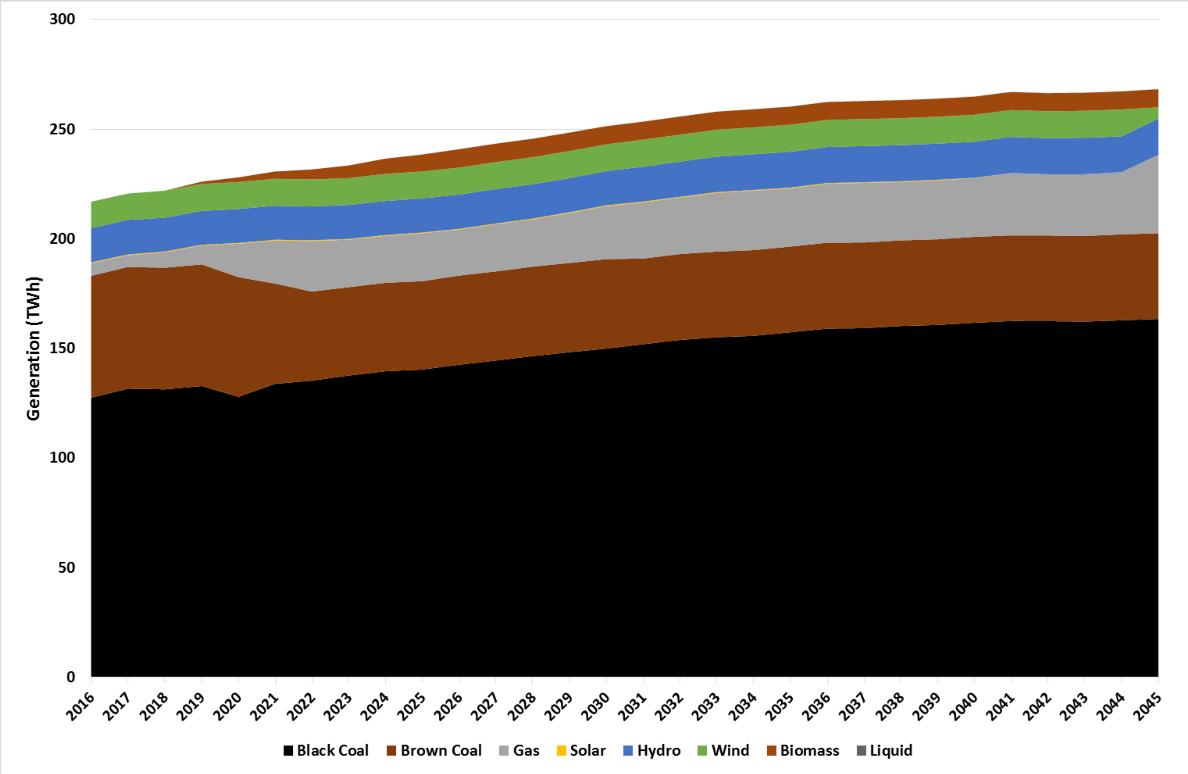

Figure 20: Generation profile by technology type for Scenario 1

A marginal change in yearly renewable installed capacity is barely enough to change the rate of carbon emissions (see **Figure 23**). Furthermore, as seen in this figure, the emissions intensity factor (EIF, tonnes of CO_2 emitted per MWh), converges towards the estimated EIF of 0.82tCO_2 over the period 2045 it regains its momentum upwards toward 0.85. The emissions constraint of 0.65tCO_2 is the estimated requirement to reduce atmospheric carbon levels from the Australian stationary energy industry [148].

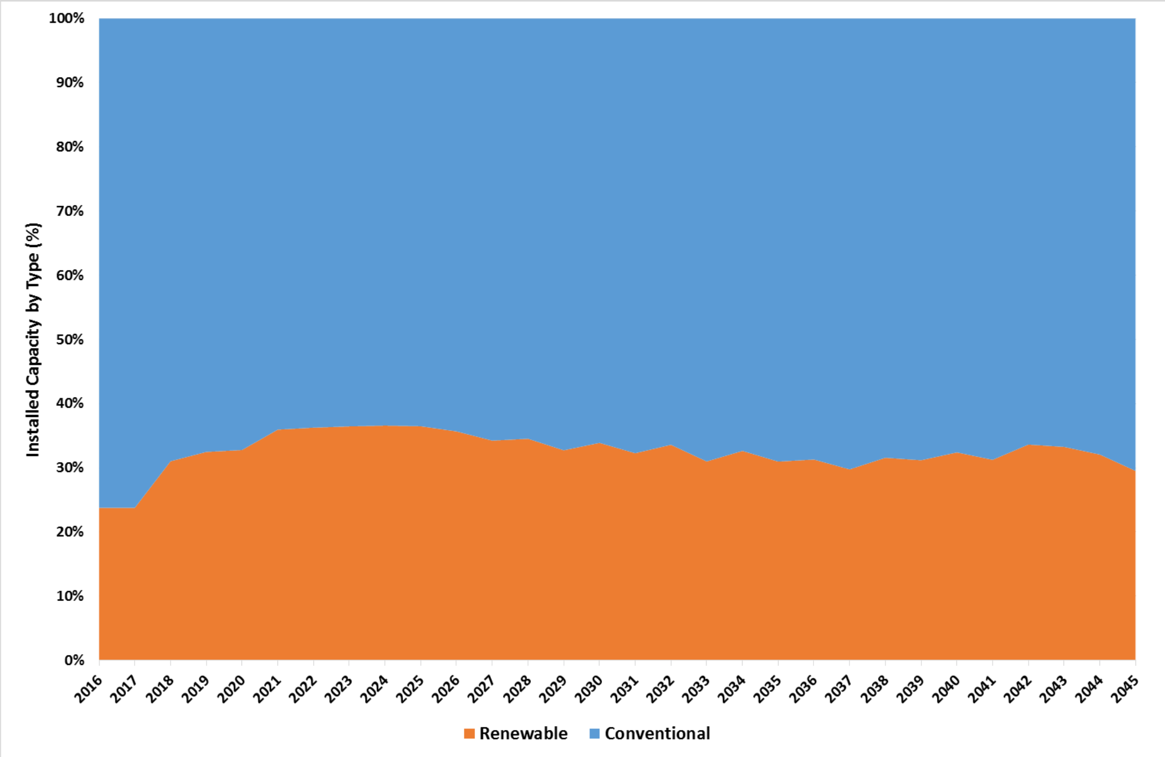

Figure 21: Installed Generation Capacity with respect to technological share

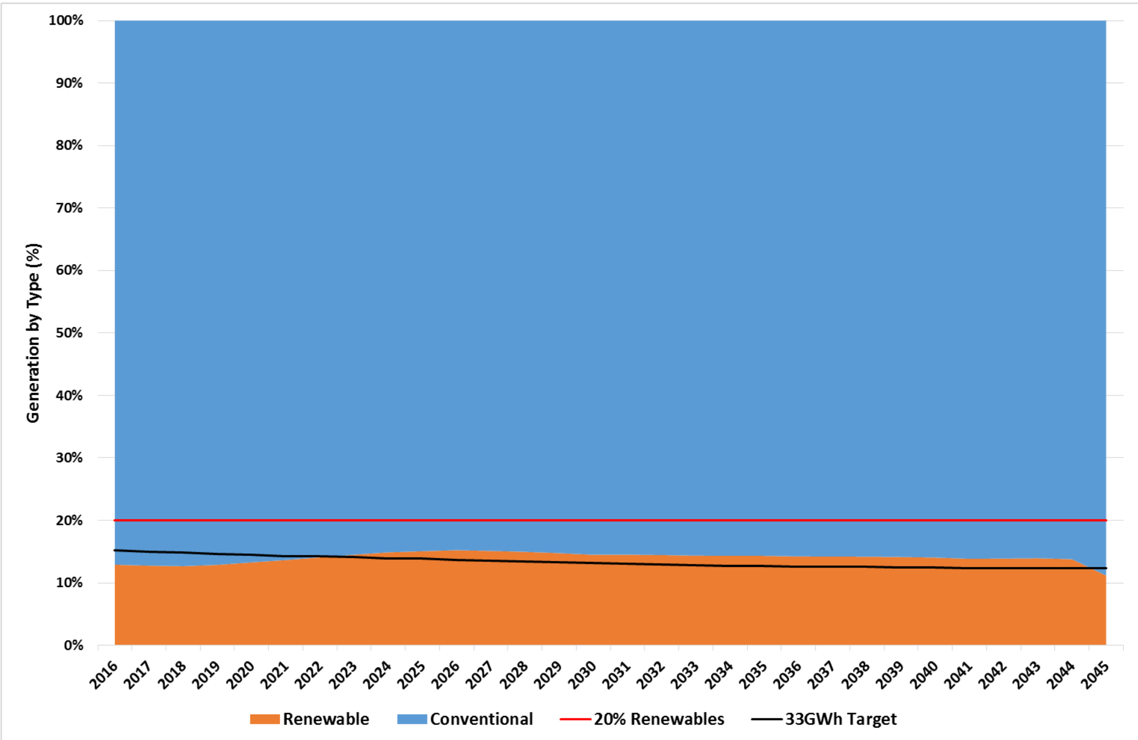

Figure 22: Generation Dispatch Quantities with respect to Conventional and Renewable Technologies

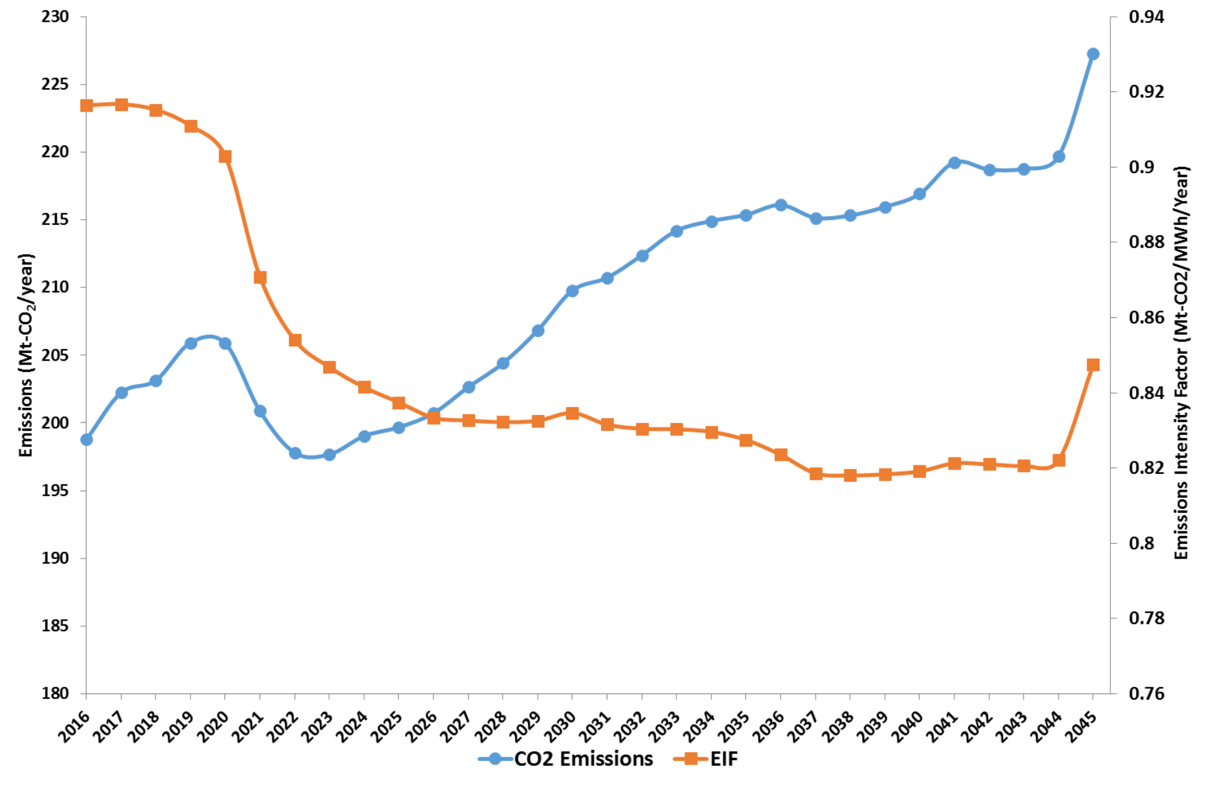

Figure 23: Carbon Emissions due to combustion in Scenario 1

5.7.3 Concluding remarks

While these results do highlight some interesting consequences for the Australian electricity sector, it should not be misinterpreted to reveal a likely outcome. The significant increase in global natural gas exploration and production have and will continue supress prices while in the long term lead to consolidation. Certainly this change in ownership of resources and their optimal extraction and expansion will be retimed within each producer's greater global portfolio. Moreover, the most likely outcome is that withholding of capacity will be a result of this immediate glut of cheap supplies.

The consequences for the electricity sector in Australia are that the volatility of world LNG prices will present other issues surrounding the availability of supply. In this case, we are more likely to see rapid spikes in prices that are induced by capacity transferal between the super majors of Oil. However, it is certainly of interest to note that the willingness to deploy renewable energy technology into the national market will be tested by such low input prices of production.

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